MONENCO LIMITED

THE REALISTIC POTENTIAL
FOR DISTRICT HEATING IN CANADA
VOLUME I

(Volume 1 of 2)

Prepared by

Monenco Consultants Limited

in association with

DHM Energy Consultants Ltd.
K-Konsult
Cogeneration Associates Limited

April, 1985

Monenco

Monenco Consultants Limited
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Mr. M. Wiggin
Program Manager - Energy Systems
Office of Energy Research and Development
Energy, Mines and Resources, Canada
500 Booth Street, 9th Floor
Ottawa, Ontario
K1A 0E4

Dear Mr. Wiggin:

Re: The Realistic Potential for District Heating in Canada
DSS File No. 02SQ.23218-30018
DSS Contract Serial No. 00Q83-00303

We are pleased to submit our report on "The Realistic Potential for District Heating in Canada". The report has been prepared by Monenco Consultants Limited (formerly known as Montreal Engineering Company, Limited) in association with DHM Energy Consultants Ltd., K-Konsult, and Cogeneration Associates Limited. The document has been assembled in two volumes with Volume 1 containing Parts 1-6 and Volume II containing Parts 7-11.

The study has indicated that district heating can be competitive with conventional heating alternatives in some segments of Canadian space heating market. However, the proportion of the space heating market in which the technology can be competitive is highly dependent on the amount of cross-subsidization that is possible between high density and low density heat loads and the level of market penetration that district heating can achieve in the face of non-economic barriers to implementation.

The study considered the feasibility of district heating in urban centers representing a total population of about 13 million. These centers are estimated to have a total requirement for space and domestic hot water heating in the residential and commercial sectors of about 600 PJ per year of useful heat. With cross-subsidization of lower density heat loads in these centers by the high density heat loads, and 100% market penetration in areas where it is

.../2

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competitive, it is estimated that district heating could economically supply up to 50 per cent of this requirement. With no such cross-subsidization, and 50 per cent market penetration in areas where it is competitive, the proportion of the space heating market that could be economically supplied by district heating is reduced to about 5 per cent of the total requirements due to losses of economies of scale.

Cross-subsidization will tend to reduce the economic incentives to convert to district heating for high heat density consumers. Consequently, there is a limit to the amount of cross-subsidization that can take place before such a policy may begin to have a negative impact on the total level of market penetration. Thus, the 50 per cent and 5 per cent values likely represent the upper and lower limits of the space heating market for these urban centers, that could be realistically served by district heating.

We trust you will find the report to be satisfactory and we shall, of course, be available to discuss any aspects of it further with you at your convenience.

Yours very truly

M.A. Pavey.

M.A. Pavey, Eng.
Vice-President Utility Management

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1.1 GENERAL

The International District Heating Association (IDHA) describes district heating (D H) as a method by which thermal energy from a central source is distributed to residential, commercial and industrial consumers for use in space heating, water heating, and process heating. This definition encompasses not only relatively small systems such as group heating projects or "block centrals" but also very large systems which may serve an entire city.

District Heating has enjoyed wide acceptance in many countries in Europe where the technology is considered to provide substantial economic benefits compared to individual heating systems. There are a number of other benefits, not entirely of an economic nature, that are associated with district heating and accrue to individual consumers or society as a whole. Some of the major benefits are:

(i) energy conservation through the use of central heating plants which are generally more efficient than individual heating installations;

(ii) conservation of the high grade fuel or energy forms (natural gas, oil, electricity) normally consumed in individual heating systems through the substitution of low grade fuels such as coal, wood or municipal solid waste which can only be practically utilized in larger central heat stations;

(iii) greater fuel substitution flexibility since neither the distribution network nor subscriber heat installations of a D H system are affected by a change in fuel type at the central heating plant;

(iv) greater security of heat supply since the central heat station is normally designed and built with allowances for reserve or back-up capacity which are impractical for the majority of individual heating systems;

(v) district heating can, in certain circumstances, reduce the level of particulate and gaseous emissions released into the atmosphere, as well as the level of thermal pollution.

In view of the benefits associated with district heating and the limited acceptance that the technology has enjoyed in Canada, Energy, Mines and Resources, Canada commissioned this study to establish the realistic potential for the development of district heating in this country. The objectives of the study were to:

(i) Review and document recent work in Canada relating to district heating;

(ii) Establish the realistic potential for district heating in Canada and determine the general circumstances and conditions necessary to realize potentials which exist.

(iii) Document the development of district heating in countries in which the technology is well entrenched and explain how and why this was achieved.

(iv) Identify the principal barriers to implementation of district heating and suggest means for their resolution.

(v) Identify and quantify the principal benefits that may be realized by both the public and private sectors as a result of the successful deployment of district heating.

The study has been carried out by Monenco Consultants Limited (formerly known as Montreal Engineering Company, Limited) in association with DHM Energy Consultants Ltd., K-Konsult of Sweden, and Cogeneration Associates Limited.

The study has indicated that district heating can be competitive with conventional heating alternatives in some segments of the Canadian space heating market. However, the proportion of the space heating market in which the technology can be competitive is highly dependent on the amount of cross-subsidization that is possible between high density and low density heat loads and the level of market penetration that district heating can achieve in the face of non-economic barriers to implementation.

The study considered the feasibility of district heating in urban centers with a total population of about 13 million. These centers are estimated to have a total requirement for space and domestic hot water heating in the residential and commercial sectors of about 600 PJ per year of useful heat. With cross-subsidization of lower density heat loads in these centers by the high density heat loads, and 100% market penetration in areas where it is competitive, it is estimated that district heating could economically supply up to 50 per cent of this requirement. With no such cross-subsidization, and 50 per cent market penetration in areas where it is competitive, the proportion of the space heating market that could be economically supplied by district heating is reduced to about 5 per cent of the total requirement due to losses of economies of scale.

Cross-subsidization will tend to reduce the economic incentives to convert to district heating for high heat density consumers. Consequently, there is a limit to the amount of cross-subsidization that can take place before such a policy may begin to have a negative impact on the total level of market penetration. Thus, the 50 per cent and 5 per cent values likely represent the upper and lower limits of the space heating market for these urban centers that could be realistically served by district heating. These conclusions are discussed in more detail in Part 1.5 of this summary.

Since the size of the main body of the study report may tend to limit the extent of its distribution, this summary has been prepared on a "stand alone" basis that would allow its distribution independent of the main body of the report. Consequently, the discussion and amount of background material which follows in this summary is somewhat more comprehensive than would otherwise be the case.

111 DISTRICT HEATING SYSTEMS

All DH systems consist of three major components:

- the heat plant;
- the transmission and distribution systems; and
- the subscriber systems.

Each of these components is discussed in greater detail in the main body of the report; however, a brief description of the function of each may be useful to gain a general overview of the physical characteristics of a DH system. A simplified diagram of a typical D H system is presented in Figure 1-1.

The heat plant may consist of any combination of heat-only units, units which produce both heat and electricity, called cogeneration units, waste heat recovery units, and auxiliary heat units for standby and peaking purposes. The heat plants are not necessarily located at a single site but, rather, may provide heat to the system from a number of locations. The plants produce heat for the transmission and distribution networks in the form of either steam or hot water.

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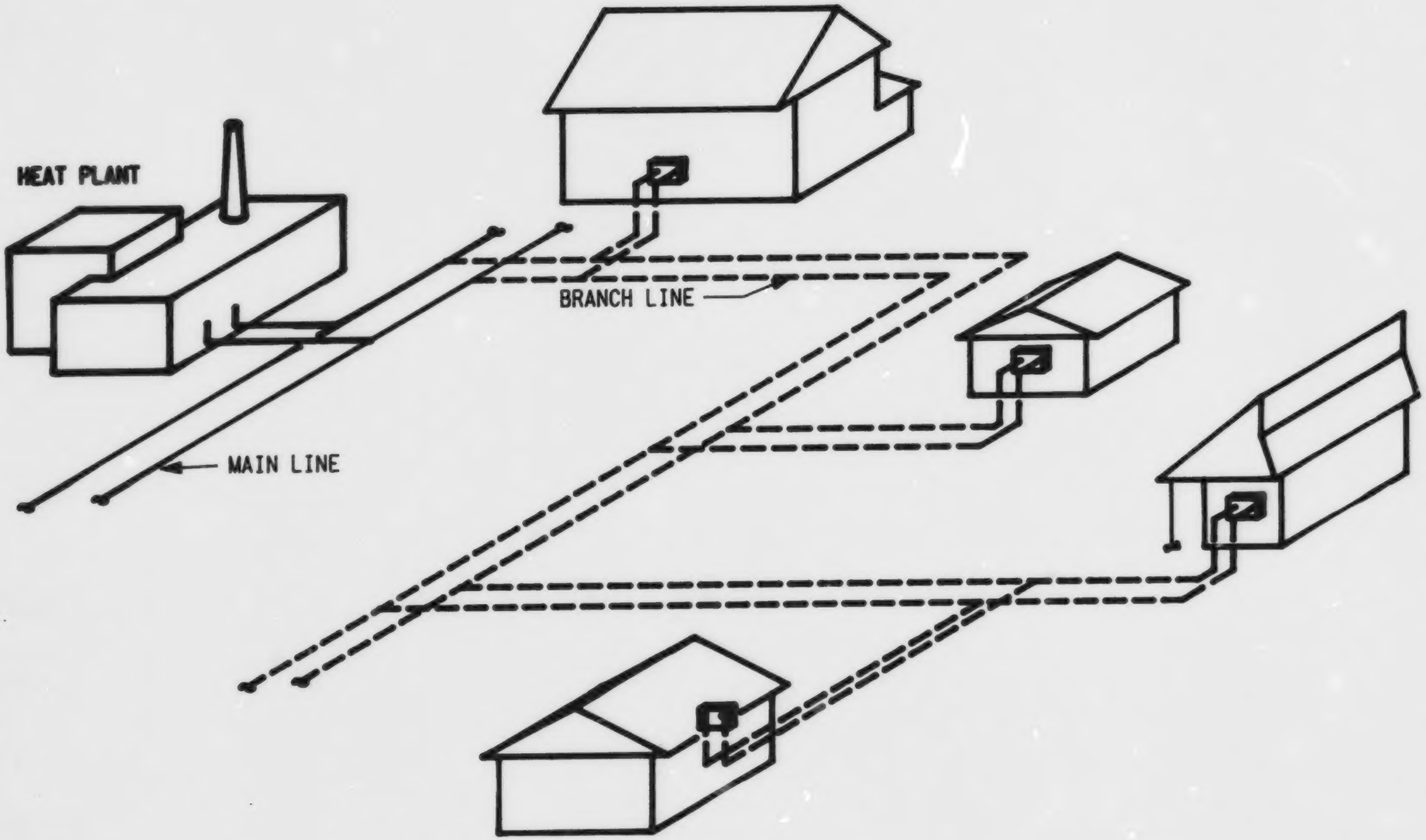
HEAT PLANT
BRANCH LINE
MAIN LINE

FIGURE 1-1
DISTRIBUTION NETWORK

If the distribution network heat transfer fluid is steam and the plant is for heating only, the steam is produced by a steam boiler at whatever pressure is necessary for the system, usually between 700 and 1400 kPa. If the distribution network heat transfer fluid is hot water, the plant may be either a hot water or steam generator. With a hot water generator, the water can be delivered directly to the distribution network or the system can be a closed circuit operation, transferring heat through heat exchangers to the distribution system water. When a steam generator is used, the heat can be delivered to the distribution network only through a heat exchanger. Hot water D.H. systems usually fall into three temperature categories - low, medium, and high temperature. It is common practice to vary the supply temperature for each category according to the heat demand, however, the maximum supply temperatures are approximately 90°C, 120°C, and 200°C respectively.

The transmission system is the initial part of the heat distribution network. It usually consists of a pair or several pairs of trunk pipelines to transmit the heat transfer fluid from the heat plant to the distribution network and return it to the heat plant. If the heat plant can be built close to the heat loads, the transmission system will be of minimal length. On the other hand, if the plant is located at some distance from the heat loads, the length of the transmission system can be greater than the length of the distribution system. Transmission and distribution piping systems are insulated and may be direct buried, placed in underground metal or concrete conduits, culverts or tunnels. In some instances, the systems are run above grade, although this is less common, particularly for distribution piping.

The class of construction required for steam and high temperature hot water (HTHW) systems is usually extra heavy pipe and fittings due to the high temperature and pressure of the system. Consequently, material and installation costs for these types of distribution systems can be very high compared to the medium temperature hot water (MTHW) and low temperature hot water (LTHW) systems. In addition, the temperature of a steam or HTHW system is much higher than is acceptable for polyurethane insulation and hence, the insulation for such systems will cost more than factory applied polyurethane insulation which is suitable for the LTHW and MTHW systems.

There is essentially no difference in the pipe systems used for the transmission and distribution systems. However, unit costs for the transmission system are generally less than for the distribution network since there are few connections to it and, in most instances, the transmission system is located in open areas.

Heat is delivered from the distribution system to the consumer through subscriber owned heat exchangers. For steam DH systems, these exchangers have typically been steam/water or steam/air heat exchangers. With this type of system, steam is sometimes supplied directly to some of the air handling unit heating coils to reduce the capacity of the main heat exchanger. For MTMW systems, a main water-to-water heat exchanger may be used or the D H water could be supplied to a heat exchanger for hydronic heating and to air coils for heating the ventilation air. If the system is a low temperature system, D H water may be used directly in the subscriber heating systems as is the common practice in Denmark.

1.2 DISTRICT HEATING EXPERIENCE

District heating, as noted above, has not enjoyed the level of acceptance in Canada that it has in a number of other countries. Consequently, it was considered useful to briefly review the history and development of district heating in other countries. The purpose of this review is to identify those factors which may have acted as a catalyst in the development of district heating and to determine the extent to which those factors exist, or could be created in this country.

121 UNITED STATES

The concept of district heating is generally considered to have been first introduced in the United States in Lockport, New York in 1877 and was quickly adopted in a number of major cities, primarily as a peripheral activity to electricity generation. The size of the industry peaked in the late 1940's when low cost fossil fuels and electricity became generally available. Estimates place the total installed DH capacity at about 40 GW and energy consumption at about 430 PJ, less than one per cent of total primary energy supply. This heating load is reported to be approximately equally divided among institutional facilities such as hospitals, universities and military establishments, housing complexes and industry. The major fuel sources for the systems are oil and natural gas, and to a lesser extent, coal. There are a number of public DH systems, the largest being the 4 GW Consolidated Edison system in New York City. Most systems use steam as the heat transfer medium and operate with overall efficiencies of less than 60 per cent.

In recent years there has been increasing interest in the European hot water technology and hot water DH systems have been installed in several cities such as St. Paul, Minnesota and Trenton, New Jersey. It would appear that district heating in the United States is in a transitional phase as the industry attempts to switch from a steam-based technology to hot water.

The private sector is playing a major role in this process; however, municipal governments appear to have been the principal motivating source of recent developments. They have made significant contributions to recent DH projects, ranging from taking an ownership position in the case of Willmar, MN., to providing assistance in arranging study and project financing, and providing indirect support as major customers of these systems.

The federal government has also played a significant role in funding initial feasibility studies and has provided, not only direct project financing through the Department of Housing and Urban Development grants, but also indirect financial assistance through federal and state tax exempt revenue and industrial development bonds. Federal and state government facilities have also represented important base loads that enhanced the economic and financial feasibility of the projects particularly during the early development stages. Recent federal legislation such as the Public Utilities Regulatory Policy Act (PURPA) and the Power Plant and Industrial Fuel Use Act (FUA) appears to have had mixed results in its impact on the prospects for district heating, creating incentives in some instances, obstacles in others and in some cases, potential conflicts with other legislation.

122 EUROPE

The Dresden system in Germany, commissioned in 1900, is considered the first D H system in Europe. In addition, several other D H systems were started in Europe in the 1920's, including systems in Hamburg, Kiel, Leipzig and Copenhagen. District heating has developed rapidly in some European countries in recent decades and market penetration is very high in Denmark, Finland and Sweden. In Denmark district heating serves more than 40 per cent of all space heating requirements and in Sweden and Finland, approximately one third of all space heating is provided by district heating. Market penetration in the Netherlands however has been quite modest. In absolute terms, district heating has been made its greatest impact in Germany. Table 1-1 shows district heating's market share in a number of European countries. Figure 1-2 illustrates the expansion of district heating in selected European countries since 1960.

TABLE 1-1

District Heating Market Share for
Selected European Countries

Country	Percent Share of Heating Market
Austria	10
Switzerland	5
Germany	10
Denmark	40
France	10
Netherlands	2
Sweden	30
Finland	30

Sources: District Heating and Combined Heat and Power Systems, OECD 1983 and Proceedings of the IDHA 1984.

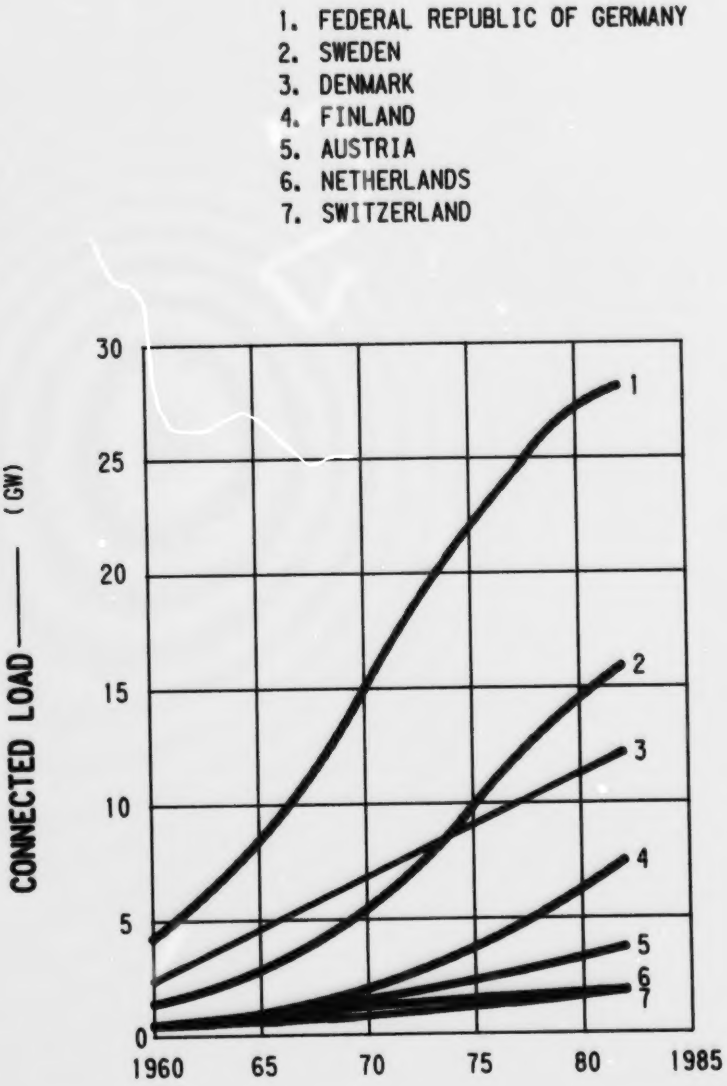

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FIGURE 1-2
DEVELOPMENT OF CONNECTED HEAT LOAD

SOURCE: IDHA (1984) PROCEEDINGS - EXPERIENCES WITH FORCED EXTENSION OF THE DISTRICT HEATING SUPPLY IN THE FEDERAL REPUBLIC OF GERMANY -H.P. WINKENS

The reasons for the development of district heating in Europe differ among countries, nevertheless, the common driving force has been the desire to produce a commodity - heat - with or without power, which is cost-competitive with alternative heat production methods. Following World War II, concerns in some European countries over the adequacy of heat and power supplies led to development of district heating. Government encouragement and, in some cases, coercion through legislation permitting mandatory connection policies and, in some instances, very significant financial assistance led to the development of many district heating and combined production systems at both the municipal and regional levels. The reasons for government support have, in some instances, gone beyond the objectives of fuel conservation, and use of indigenous resources to achieve security of energy supply. For example, in the case of Germany, government support was extended to maintain employment levels in the cool industry. During the decades that followed the war, increased concern about the environment resulted in increased interest in district heating. The oil crisis in 1973/74 provided further incentive for energy conservation and oil substitution.

Many of these countries have developed comprehensive energy plans in an attempt to rationalize the development of competing energy forms and avoid the installation of competing capital intensive energy distribution systems in the same region. The significant traditional involvement of municipal government, as well as regional and national governments, in the energy sector appears to have had a positive impact on the development and implementation of these plans.

Most D H systems have been developed and operated by organizations at the local level. In Sweden and Finland, almost all D H systems are managed by municipal utilities. In Denmark, where the cooperative movement has a long history, D H systems are managed by local cooperative organizations as well as by municipal utilities. In Germany, both municipalities and private companies have contributed to the development of district heating. Ownership is also mixed in the Netherlands.

With the exception of hydroelectric resources, Finland and Sweden are not well endowed with major indigenous energy resources and did not have access to natural gas resources until very recently. In other European countries such as Austria, Belgium, Germany, Ireland, the Netherlands, Norway and the United Kingdom, the market penetration for district heating has not reached the same levels. During the post-war period, some of these countries could rely on hydroelectric power, coal or peat. In addition, the subsequent development of natural gas resources and the European gas grids provided another attractive energy alternative. The availability of natural gas has had a significant effect on the level of penetration of district heating in countries like the Netherlands.

Natural gas has also been recently introduced in Denmark, Sweden, and Finland. As a newcomer in the heating market, it has not yet affected the market share of district heating in these countries; however, depending on its use either as a fuel for district heating or a fuel for individual heating systems, its impact on the future potential for district heating could be positive or negative.

On the basis of the foregoing, it would appear that the major factors contributing to the extensive development of district heating in a number of European countries have been:

(i) the absence of low cost conventional indigenous energy resources such as oil, natural gas, and hydroelectric resources;

(ii) government structures that permitted detailed integrated planning in the energy sector by national, regional and municipal governments;

(iii) a long tradition of cooperative action at the local level which improved the acceptability of local district heating projects;

(iv) an apparent willingness on the part of the populace to accept controlled access to energy alternatives and the principal of compulsory connections; and

(v) substantial government financial and legislative encouragement (and coercion) for the development of district heating to promote energy efficiency, the use of indigenous resources and in some cases to provide industrial support.

123 CANADA

District heating systems in Canada are limited to relatively small sections of cities, university campuses, military bases, airports and the federal government buildings in the National Capital Region of Ottawa/Hull. Most of these systems use steam as the heat transport fluid but some federal government systems use HTHW. Many of the existing heating plants were originally designed to burn coal but most boilers have been modified to burn oil and/or natural gas. The major municipal or municipally franchised systems are located in Montreal, Toronto, London, Winnipeg and Vancouver. They were developed to supply heat to commercial buildings and some industry in the cities' core. Major government systems are owned by Public Works Canada, with eleven DH systems in Ottawa/Hull, and the Department of National Defence, which operates systems on each military base across the country. In addition, Transport Canada owns and operates DH systems on most major airports. The Northern Canada Power Commission, a Federal Government crown corporation, owns and operates DH systems in Inuvik and Frobisher Bay, in the Northwest Territories.

The availability of low cost energy alternatives for heating, such as light oil and and more recently, natural gas and electricity, through established distribution networks has had a detrimental effect on the acceptance and development of district heating in this country. With the recent development of surpluses of natural gas and electricity, new energy technologies such as district heating are likely to be faced with even greater competitive pressures. In addition, the price differential between the cost of fuel used in individual heating systems and DH heat plants has been reduced considerably. In the sixties, a DH system could obtain heavy oil at approximately 40 per cent of the price paid by the individual consumer for light fuel oil with the same heat content. This compares with a corresponding ratio of approximately 78 per cent for fuel oil and 68 per cent for natural gas at current prices. It is apparent that with this diminishing fuel price advantage, the operating efficiency of the DH system must be somewhat better than the individual heating systems to offset the high cost of installing and maintaining a DH system if the system is to remain viable. Unfortunately, the average operating efficiency achieved by many of the existing DH systems is approximately the same as that achieved by most individual home heating systems and is, in fact, less than the efficiency achieved by many heating systems in office and apartment buildings.

In addition to greater competitive pressures faced by district heating in Canada relative to some European countries, the ability, or desire of government to influence the development of district heating appears to be less than in Europe. Federal government initiatives in the energy sector in recent years have been oriented more towards promoting energy conservation and reducing oil consumption in order to achieve energy self-sufficiency than to promoting any specific alternative energy form. It has been left largely to competitive market forces to determine what alternative energy forms will satisfy that displaced demand. While programs developed to encourage oil substitution have been effective in reducing oil consumption, the major beneficiaries of this policy have been the other conventional energy sources, natural gas and electricity, which have absorbed most of oil's lost market share.

While the federal and provincial governments play significant roles in the energy sector in Canada, municipal governments, which have taken leadership roles in D H initiatives in Europe and the United States, are generally not, with the exception of municipal electric utilities in Ontario, significantly involved in the energy sector. There are very few municipalities involved in the production and distribution of primary or secondary energy forms that might be compatible with development of district heating.

In addition, responsibilities in the energy sector are divided between the federal and provincial governments. This makes the type of detailed national and regional planning and rationalization of competing energy forms (which appear to have aided in the development of district heating in Europe) much more difficult to accomplish in Canada.

It would appear that many of the factors contributing to the development of district heating in Europe, do not currently exist in Canada and future prospects for the development of district heating in this country will depend on the ability of the technology to compete economically with existing energy forms.

1.3 THE CANADIAN ENVIRONMENT

An assessment of the realistic potential for district heating must recognize the more important characteristics of the Canadian space heating market in which the technology will operate and compete.

In common with other energy distribution systems such as natural gas and electricity, district heating is highly capital intensive. As such, it requires a large and relatively stable cash flow (and consequently a large heat load) to support the high fixed costs associated with the capital investment in the system. In addition, two of the three components of a D H system, the heating plant and distribution network, are significantly affected by economies of scale, with the result that the delivered cost of heat from a D H system will tend to decrease with increasing heat loads and heat densities. The effects of scale can have a dramatic and positive impact on the ability of district heating to compete with established conventional energy forms.

131 DISTRICT HEATING PARAMETERS

The approach taken in the study has been to identify the major demographic and climatological factors that are likely to create the higher heat loads, necessary to support district heating, and the areas where the costs of competing energy forms tends to maximize the economic incentive to adopt district heating. The parameters that have been chosen are:

(i) climate
(ii) population and population density
(iii) existing heating equipment
(iv) alternative energy forms.

The two climatological parameters that are of greatest importance from the point of view of district heating are annual degree days (DD) and outdoor design temperature. These data can provide a means of estimating relative heat consumption and demand for the different climatic regions of Canada and identifying those areas likely to have relatively higher heat loads due to climate. For purposes of this study, the impact of climate on both relative energy consumption and heat demand for space heating was based on annual degree days.

The building stock of cities changes in many ways as cities grow in population with, for example, multi-family dwellings becoming a larger proportion of a city's dwelling units as population increases. The difference in the amount and type of building stock between a small and a large city not only affects the total heat consumption but also the relative heat density, both of which will have an effect on the feasibility of district heating. Larger office and apartment buildings will increase both heat density and heat loads as well as reduce connection density. These factors will tend to reduce the unit cost of energy delivered from a DH system and, consequently, a larger city, with a greater population and higher population density will likely have more potential for district heating than a smaller one.

The investment for subscriber heating equipment is an important part of the total cost of a DH system and retrofit costs, to convert a building to district heating are significantly affected by the type of existing heating system (forced air, hot water or hydronic, electric baseboard). For example, a house with electric baseboard heating will require a complete replacement of its heating system to accept district heating while a house with a hot air or hydronic system can continue to use existing ducting or piping when retro-fitted to district heating. The difference in cost can be substantial. Table 1-2 shows the proportions of existing urban

TABLE 1-2

Existing Urban Residential Space Heating Equipment - 1981
(Percent of Dwelling Units)

Province	Hydronic	Forced Air	Electric	Other
Newfoundland	20	31	37	12
Prince Edward Island	60	30	3	6
Nova Scotia	43	40	11	6
New Brunswick	34	37	23	6
Quebec	26	25	40	9
Ontario	25	57	15	3
Manitoba	16	62	19	3
Saskatchewan	18	74	4	4
Alberta	19	73	4	4
British Columbia	21	55	19	5
Canada	24	49	21	6

Source: Statistics Canada, "Occupied Private Dwellings - Selected Characteristics", Catalogue #92-932.

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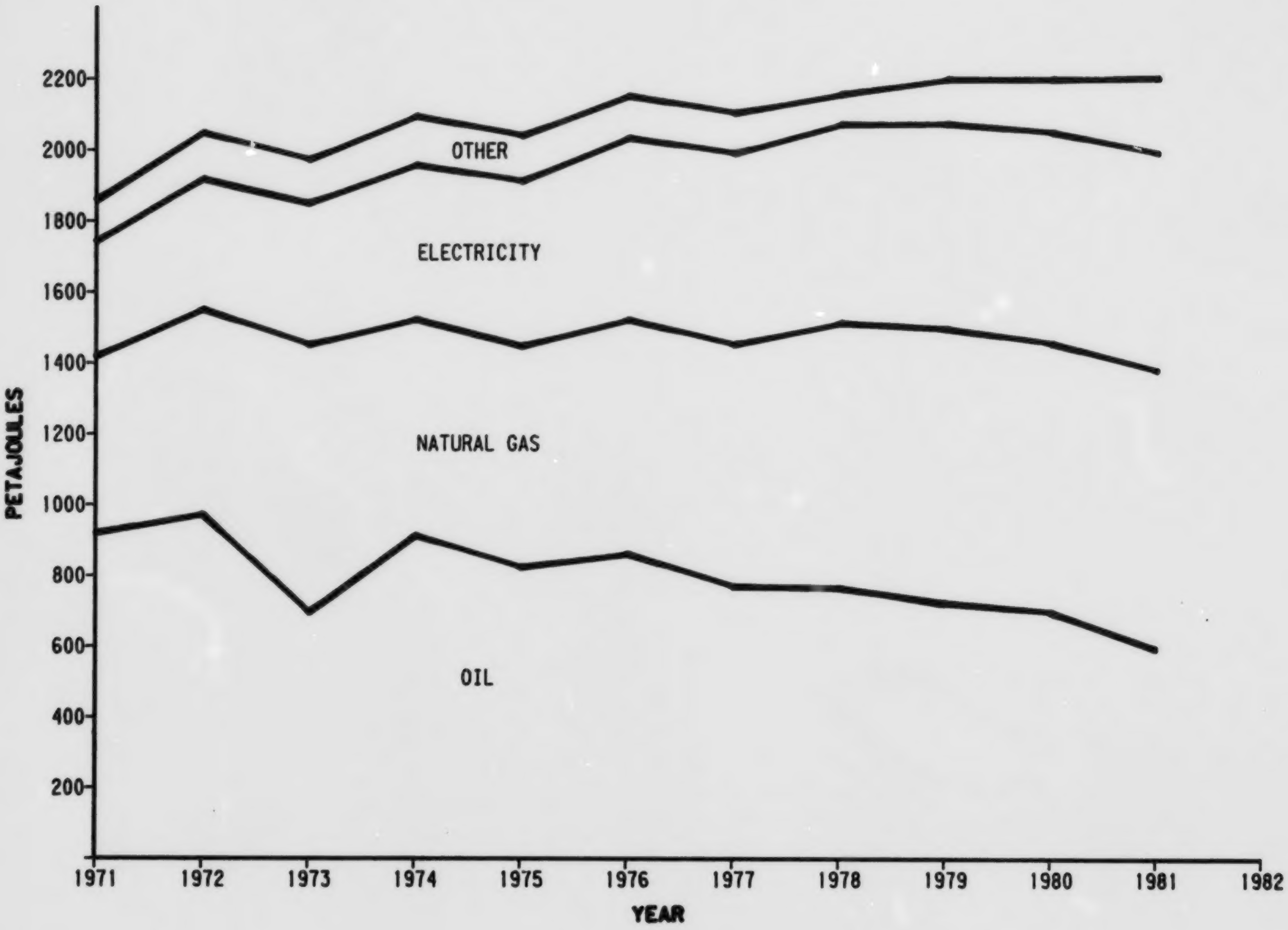

FIGURE 1-3
ANNUAL ENERGY COMSUMPTION IN CANADA
BY THE RESIDENTIAL AND
COMMERCIAL SECTORS

residential heating equipment types by provinces. As can be seen from the table, both Newfoundland and Quebec have a high percentage of electrically heated residences. This indicates that conversion of subscriber heating systems to accept district heating will likely be more costly in these provinces than in a province like Prince Edward Island which has a low proportion of electric heat and a relatively high proportion of hydronic heating systems.

While there are a number of different fuel types or energy currencies with which district heating must compete in the residential and commercial space heating market such as oil, natural gas, electricity, coal, wood and others, it is clear from Figure 1-3 that the principal energy forms used by the residential and commercial sectors are oil, natural gas and electricity. Considering the relative prices for natural gas, electricity and oil, the opportunities for district heating will, all other things being equal, be greater in those parts of the country where, due to the unavailability of natural gas and relatively high electricity costs, oil continues to maintain a large proportion of the space heating market. Table 1-3 shows the share of the urban residential space heating market (expressed as a per cent of dwelling units) held by the principal fuel types in each province. Natural gas tends to be the dominant fuel type in the West, oil and natural gas or electricity hold significant market shares in central Canada and Newfoundland while oil is the dominant fuel in the Maritime Provinces. Consequently, the price competition facing district heating would, at least until natural gas from the Scotian Shelf is commercially available, likely be weakest in the Maritime Provinces.

TABLE 1-3

Urban Residential Space Heating Market Share by Fuel Type - 1981
(Percent of Dwelling Units)

Province	Oil	Gas	Electric	Other
Newfoundland	56	-	38	6
Prince Edward Island	92	-	4	4
Nova Scotia	83	-	12	5
New Brunswick	71	-	24	5
Quebec	49	8	42	1
Ontario	28	54	17	1
Manitoba	8	70	21	1
Saskatchewan	2	90	7	1
Alberta	1	91	8	-
British Columbia	22	53	23	2
Canada	31	44	24	1

Source: Statistics Canada "Occupied Private Dwellings - Selected Characteristics" Catalogue #92-932

POTENTIAL DISTRICT HEATING SITES

The 1981 census provides extensive information on populations, population densities, housing types and heating equipment for different regions in Canada. These data have been used to develop the estimated heat loads and heat densities of the cities that were chosen for analysis.

Two criteria have been used in the initial screening process of selecting potential DH sites - population and population density. The minimum population density considered is 800 inhabitants per km^2. This criterion limits the amount of large, low heat density areas to be included in the analysis. It is reasonable to assume that the average heat density below this limit is very low. For example, if there were an average of 2.5 inhabitants in each residential unit and each unit consumed 124 GJ per year, the heat density would be 40 MJ/m^2. This heat density is not sufficient to justify the installation of a D.H. system. The selection of sites was also based on a minimum population of 10,000. European experience indicates that the potential for district heating is substantially reduced below this population level.

These two criteria eliminate, for the purposes of this study, approximately six million of 19 million Canadians living in urbanized areas at the time of the census. The classification of the various remaining Canadian communities that passed this initial screen has been carried out using three parameters: population, degree days and type of heating system.

Three population classifications were used in the study.

- the three largest cities (Toronto, Montreal, Vancouver) with more than 900,000 inhabitants;
- 100,000 to 899,999 inhabitants; and
- 10,000 to 99,999 inhabitants.

The bulk of Canadian cities experience annual degree days that vary between 3000°C and 6000°C. Therefore, the three following categories were selected for this classification:

- annual degree days less than 4,000°C;
- annual degree days between 4,000 and 5,000°C; and
- annual degree days greater than 5,000°C.

Due to the high percentage of electrical heating in Quebec and because the retrofit costs are high for such systems, locations in Quebec have been classified separately. Newfoundland also has a high percentage of electrical heating, however, because only three Newfoundland communities have been considered, they have not been classified separately.

The towns and cities that have been considered as potential D.H. sites are classified as shown in Table 1-4. and are listed in order of decreasing population.

133 THE CANADIAN MODEL

The capital cost of district heating, expressed in terms of the unit cost of energy, decreases rapidly with increasing heat density. Consequently, a heat density analysis is often used in the early stages of a DH study or in energy planning to evaluate which areas of a city are more suitable for district heating and should be studied more closely. A group of selected Canadian cities were analyzed in a very preliminary manner in order to develop a typical heat density "map" that could, for purposes of this study, be applied to any Canadian city.

In an attempt to quantify the heat densities in the different areas in most cities, five heat density zones within a typical city have been defined.

Table 1-4

Classification of Census Metropolitan Areas and Census Agglomerations

Population (000's)	Location	Annual Degree Days		
		<4000°C	4000-5000°C	>5000°C
900	Quebec		Montreal (2651)	
	Other	Vancouver (969)	Toronto (2811)	
100 - 899	Quebec		Hull (149)	Quebec City (478) Chicoutimi (110)
	Other	Hamilton (326) Windsor (212) Victoria (177) St. Catharines (124)	Ottawa (389) London (254) Kitchener (139) Halifax (115) St. John's (110) Oshawa (100)	Calgary (593) Winnipeg (564) Edmonton (549) Regina (162) Saskatoon (154) Thunder Bay (112) Sudbury (100)
10 - 99	Quebec		Sherbrooke (83) Drummondville (39) St. Hyacinthe (38) Trois Rivieres (32) Valleyfield (30) St. Jean (25) Sorel (23) Victoriaville (22)	Shawinigan (47) Rimouski (28) Sept-Iles (26) St. Jerome (25) Thetford Mines (20) Val d'Or (19) Riviere du Loup (13)
	Other	Brantford (72) Kamloops (55) Sarnia (51) Chatham (41) Port Albernia (20) Vernon (20) Leamington (13)	Kingston (75) Saint John (73) Guelph (71) Dartmouth (62) Peterborough (61) Lethbridge (54) Moncton (53) Sydney (51) Barrie (38) Belleville (35) Stratford (26) Corner Brook (24) Orillia (24) Brockville (20) Owen Sound (20) Sydney Mines (19) Charlottetown (17) Cobourg (16) Cranbrook (16) Prince Rupert (15) Trenton (15) Lindsay (14) Pembroke (14) Hawkesbury (10) New Glasgow (10)	Sault Ste. Marie (75) Red Deer (46) Moose Jaw (34) Thompson (14) Labrador City (12)

1. Core: High density commercial section.

2. Residential: The peripheral area consisting mainly of detached and semi-detached housing.

3. Intermediate: These areas generally lie between the core and the residential areas and consist mainly of residential units ranging from detached to high rise apartment buildings. Lots are generally small relative to the floor area. This area includes some commercial development such as offices, clinics and shopping centers.

4. Industrial: Most cities have some type of industrial development. Although some industrial loads may be attractive for district heating, the diverse and often unique characteristics of such loads make them impractical to consider in a study of this nature.

5. Rural: Small rural communities which surround most cities are not included in this study because the heat loads and heat densities are too low for district heating to be economically feasible.

Estimates of heat load densities for the core, intermediate and residential areas of the cities analysed showed a high degree of variability, however, some elements of consistency did occur despite differences in size and make-up of the cities. On the basis of these analyses, a simplified heat load model was developed for use in the study and is presented in Table 1-5. It is not intended that the model be applied to any specific city, particularly considering the variability of results flowing from the analyses of the representative

TABLE 1-5

Estimated Heat Load Characteristics of Typical Canadian Cities

Population	>900,000			100,000 - 899,999			10,000 - 99,999		
Annual Degree Days (000's)	<4	4 - 5	>5	<4	4 - 5	>5	<4	4 - 5	>5
Total Heat Consumption (GJ per capita)	35	45		35	45	55	35	45	55
Distribution of Total Heat Consumption by Heat Density (per cent)									
Core		25			10			10	
200 - and above*		60			10			10	
100 - 199 MJ/m^2		12			30			30	
0 - 99 MJ/m^2		3			50			50	
		100			100			100	
Heat Densities (MJ/m^2)									
Core	1170	1500		780	1000	1220	580	750	920
200 - and above*	270	350		170	220	270	170	220	270
100 - 199	115	150		100	130	160	100	130	160
0 - 99	40	50		25	30	35	25	30	35

* - excluding core area

sites. The model cannot claim to describe an "average" city in Canada, but it could be assumed that a large number of Canadian cities follow a pattern that is similar to the pattern outlined in the model.

1.4 DISTRICT HEATING SYSTEMS

There are a large number of possible fuels, heat plant types and distribution system configurations that could be considered in evaluating the economic feasibility of district heating. The systems that were used in the study are described below.

141 ENERGY SUPPLY SYSTEMS

District heating plants can use conventional fuels such as natural gas, heavy oil or coal as their primary energy source. In addition, the size of the heat load associated with a D H project may support the capital investment in heat plant equipment necessary to take advantage of lower quality, lower cost fuels or energy resources for which there might otherwise be no use. Examples of such low grade resources are wood, peat, municipal and industrial solid combustible waste, low grade coals, including lignites, low grade liquid and gaseous effluents from municipal, industrial and utility sources, geothermal energy, and petroleum cokes, pitches and oil shales. A great deal of research and development work is underway investigating the technology and economics of converting low grade energy resources into high grade, economically transportable liquid and gaseous fuels. However, low grade resources are often not available in large enough quantities within a small enough area to permit upgrading and product transportation facilities, on an economic scale, to be sited in one place. Small quantities of low grade energy resources, however, are often available within economic transportation distance of centres of population and, consequently, should be considered by any community reviewing the feasibility of district heating. The heat plant fuels considered in this study included natural gas, heavy oil and coal, wood, peat, and municipal solid waste.

The type and number of units included in a central heating plant for district heating are very site specific, and dependent on such factors as heat load requirements, electricity and cooling loads (if to be provided by the same station), anticipated future expansion of the system and a number of other factors. The types of plants that can be used for district heating include heat only plants based on steam or hot water, cogeneration plants producing electricity and heat as joint products, heat pump systems, and waste heat recovery systems. In addition, existing powerplants can be retrofitted for cogeneration and thermal storage devices can be used to help meet peak load requirements. There are also a number of emerging heat production technologies including advanced combustion technologies such as fluidized bed combustion, coal liquid mixtures, coal gasification, and coal-fired gas turbines that may have application in district heating.

Both heat-only plants and cogeneration plants were considered for purposes of this study. Four plant sizes were considered in order to reflect the impact of economies of scale on unit heat costs. The plant sizes considered, and the approximate population that could be served by these plants (assuming per capita space and hot water heat requirements of 45 GJ per year) are given below.

HEAT PLANT SIZES

Station Size (Thermal Load)	Population Served at 45 GJ per annum per inhabitant
18 MW	4,500
150 MW	37,500
300 MW	75,000
1500 MW	375,000

For the heat only station, the plant comprised four low pressure steam generators, each capable of meeting 33 per cent of the load (for example the 18 MW plant comprised 4-6 MW units) in order to provide for reserve or back-up capacity. The cogeneration plant also consisted of four units each of which provided 33 per cent reserve capacity. Each unit consisted of a high pressure boiler with an extraction turbine to provide base load heat and a low pressure boiler to provide peak load heat.

142 DISTRIBUTION SYSTEMS

There are essentially three fluid types that can be used to transport heat. They are organic fluids, steam and water. Organic fluids possess the desirable physical properties of having a high boiling point and a low freezing point. They are not, however, commonly used as a heat transfer fluid except for special cases because the fluid is expensive and toxic.

In steam based DH systems, steam is produced in steam generators or extracted from steam turbines and is distributed directly to the transmission system. A complete transmission and distribution network consists of steam and condensate return lines which are usually installed in metal or concrete conduits, culverts or tunnels. In many existing steam systems, the condensate pipe was never installed or is no longer in service due to pipe failure. A common practice in many older steam systems was to drain the condensate to the sewer system at whatever temperature it was discharged from the subscriber equipment.

In the early days of district heating, there were several benefits from using steam in DH systems. It has a very high latent heat of evaporation and it can be transported at a very high velocity. As a result of these characteristics, a given quantity of heat can be transported by steam fluid for distances of 2 to 3 km in smaller pipes than if the fluid were water. If however, the length of the transmission and distribution network exceeds this distance, the pipe diameter for a hot water system will be smaller. Therefore, if the transmission and distribution network is extensive, hot water is more easily transported than steam because it can be pumped while steam can only be transported by pressure head. A survey of steam DH systems in Canada indicates that they operate with overall thermal efficiencies of between 45 and 70 per cent. This is clearly unattractive and not competitive with individual heating systems. Furthermore, there is little that can be done to increase the efficiency beyond measures such as heating the make-up water and combustion air with heat recovered from the flue gases. If there are no condensate return lines or if the steam and condensate lines have insufficient insulation, it is usually not economically feasible to retrofit these systems, even if the lines are in tunnels rather than direct buried.

For the HTHW systems, construction and operating regulations in Canada and the USA are similar to those required for steam systems due to the high temperature and pressure. Consequently, the cost of the HTHW pipe system is considerably more expensive than other hot water systems. In addition, the temperature of a HTHW system is much higher than is acceptable for factory applied polyurethane pipe insulation and consequently, the insulation process is usually more expensive. Although HTHW systems generally operate at a higher efficiency than steam, none of the Canadian systems reviewed in the study had an overall operating efficiency exceeding 70 per cent. In general, HTHW systems are limited to low operating efficiencies for many of the same reasons that affect steam systems.

MTHW and LTHW systems designed with a high temperature drop, have been built and operated in Europe for more than 30 years. Most systems being built or under study in Canada and the USA will use water at these temperatures because they combine a number of attractive characteristics not offered by other heat transfer fluids including:

- high heat transport capacity;
- moderate thermal expansion requirements;
- permits sliding-temperature operation to reduce heat losses;
- permits direct connection to building heating systems without life safety concern, provided the maximum temperature is less than 100°C;
- provides a heat sink for low grade heat recovery in conjuction with heat pumps; and
- permits the use of polyurethane insulation which facilitates high performance, moderate cost factory insulated pipe systems.

The factory insulated (European) pipe system consists of a thin wall steel pipe and a heavy duty polyethylene jacket. Polyurethane is expanded into the annular space between the two pipes. The pipe, which is suitable for direct burial is manufactured in 12 m lengths complete with a wide assortment of fittings, making field installation relatively simple and inexpensive. Techniques have been developed to provide joints consisting of polyurethane insulation covered by a polyethylene joining sleeve making the complete system waterproof.

Hot water DH systems are particularly suitable for connection to the building subscriber systems. This is because the temperature of the DH supply water is controlled according to the weather conditions. This feature enables the subscriber to control the temperature of the building heating systems with a minimum of effort and cost. Other desirable features are lower temperatures in the mechanical rooms due to lower heat losses from water pipes compared to steam pipes, less maintenance and, in some cases, less cost for maintenance personnel.

Heat meters are readily available from Europe for hot water systems, however, the minimum cost for installation is about $500. This would impose a significant burden on the cost of a heating system for a single family dwelling. Common practice, in Europe, is to use a low price flow meter for such purposes but if a low cost meter were available the Europeans would use it. It is likely, of course, that a low price heat meter would be developed if there were a demonstrated requirement. On the other hand, the cost of a heat meter for a large building, while costing approximately $1,000, does not represent a significant cost relative to the cost of the heat consumed.

There is little doubt of the success of LTHW and MTHW systems installed in Europe. The prevailing view among engineers involved with district heating in Canada and the USA, favours LTHW and MTHW systems when considering new DH systems. Consequently, the analyses in this study are based on MTHW and LTHW fluids.

1.5 ECONOMIC AND OPPORTUNITY ANALYSIS

Economic feasibility can be demonstrated in several ways. One approach to determining the most economic method of serving an energy load is to compare the long-run marginal costs of alternative methods of meeting that load. This is the approach that is typically used by utility and government planners to identify the most economic method of serving an incremental energy load. Another approach is to examine the long-term costs of meeting the load based not on long-run marginal supply costs but rather long-term expectations of the purchase prices of the alternative energy forms. This approach is more typically used by the consumer in selecting the energy alternative that will most economically meet his heating requirements. This latter approach is often referred to as a commercial feasibility analysis. To the extent that long-term purchase price expections are different from the expected long-run marginal costs of supply, an economic analysis based on commercial feasibility may identify a different alternative as the preferred option from that which would be identified using the long-run marginal cost approach. For the purposes of this study, the commercial feasibility approach has been used. This is because it more closely reflects the basis upon which the consumer will make his ultimate decisions on heat supply and, consequently, provides a more realistic assessment of the potential for district heating in Canada than would the long-run marginal cost approach.

Comparisons of various energy alternatives considered in the study were based on levelized costs of useful heat delivered to the consumer over a thirty year study period. The levelized cost of useful heat is the constant value which, if assigned to each unit of useful heat consumed during the study period, results in a present value of the cost of that useful heat equal to the present value of the costs incurred to produce it. Levelized costs, expressed in terms of $/GJ, were calculated for the various energy alteratives on the basis of a thirty year study period.

151 PRIMARY ANALYSES

The primary economic analysis was based on district heating as a heat source retrofitted to existing housing stock and commercial buildings. Levelized costs of supplying a unit of useful heat were tabulated for all possible combinations of:

(i) Three heat load densities - residential, intermediate and core:

(ii) Three climatic regions - 3500, 4500 and 5500 degree days:

(iii) Three energy pricing regimes - Atlantic, Central and Western Canada:

(iv) Six heating alternatives for residential heat loads:
- electric baseboard
- natural gas hot air
- natural gas hydronic baseboard
- natural gas condensing furnace
- light fuel oil hot air
- light fuel oil hydronic baseboard

(v) Five heating alternatives for intermediate heat loads:
- electric baseboard
- natural gas hot air
- natural gas hydronic
- light fuel oil hot air
- light fuel oil hydronic

(vi) Three heating alternatives for core heat loads:
- natural gas boiler
- light fuel oil boiler
- electric boiler

These combinations resulted in a total of 54 residential heat load cases, 45 intermediate heat load cases and 27 core heat load cases.

Estimates for the price of energy, by type, for each of three regions to the end of the study period were required to provide a quantitative framework for the realistic assessment of DH potential. The principal source of this data was the Long Term Energy Supply/Demand Outlook Spring '84 Forecast published by the Energy Market Analysis and Statistics Division, Energy Strategy Branch, Energy, Mines and Resources, Canada. The lower world oil price scenario of the EM&R forecast was used for study purposes. This forecast assumes that the Persian Gulf (FOB) price of crude oil will increase at the general rate of inflation from 1984 to 1990. Over the period 1991 to 2000, the price increases at one per cent annually in real terms. This latter assumption was continued beyond the year 2000 to the end of the study period.

The following combinations of plant size, fuel types and pricing regimes were considered in determining the cost of heat supplied to a DH system:

(i) Three energy pricing regimes - Atlantic, Central and Western Canada

(ii) Four plant sizes - 18 MW, 150 MW, 300 MW and 1500 MW

(iii) Six fuel types - natural gas, heavy oil, coal, wood, peat and municipal solid waste

These combinations resulted in a total of 60 levelized heat station costs when suitable fuel types and plant sizes were matched.

Theoretically at least, the possible combination of 42 residual values with 20 heat station costs for each of three price regimes could have led to a total of 2520 cases in the primary analysis.

In order to confine the analysis to manageable proportions, it was decided to evaluate district heating only against the most economic conventional heating alternatives. The most economic conventional alternatives were identified as the alternatives having the lowest levelized cost of a unit of useful heat. Natural gas was excluded in the Atlantic Region, and recognizing their limited distribution, condensing gas furnaces were eliminated from further consideration in the retrofit analysis. On the heat plant side, it was considered that the 1500 MW plant, which could theoretically supply about 125,000 houses, was unrealistic for Canada at this time and it was also excluded from further analysis. The following cases were identified as the alternatives against which district heating would be evaluated in the primary analysis:

Heat Load Density	Least Cost Conventional Heat Source		
	Atlantic	Central	Western
Residential	Electric Baseboard	Natural Gas Hydronic Baseboard	Natural Gas Hydronic Baseboard
Intermediate	Electric Baseboard	Natural Gas Hydronic Baseboard	Natural Gas Hydronic Baseboard
Core	Light Fuel Oil Boiler	Natural Gas Boiler	Natural Gas Boiler

The economic benefits of district heating, expressed in terms of percentage savings over conventional heating alternatives are presented in Table 1-6.

This table shows the percentage difference between the total levelized cost of the least cost conventional heating alternative and

TABLE 1-6

Percentage Benefit: District Heating vs Conventional Heating Systems

Density @ 4500 DD	Station Size 18 MW	150MW	300MW
Atlantic			
Core (Light Fuel Oil Boiler)			
Minimum	4 (MSW)	30 (Peat)	38 (Oil)
Maximum	6 (Oil)	44 (Coal)	53 (Coal)
Intermediate (Electric Baseboard)			
Minimum	-	4 (Wood)	10 (Oil)
Maximum	-	16 (Coal)	25 (Coal)
Residential (Electric Baseboard)			
Minimum	-	-	1 (Wood)
Maximum	-	-	8 (Coal)
Central			
Core (Natural Gas Boiler)			
Minimum	-	-	4 (Wood)
Maximum	-	17 (Oil)	16 (Coal)
Intermediate (Natural Gas Hydronic Baseboard)			
Minimum	-	-	-
Maximum	-	-	4 (Coal)
Residential (Natural Gas Hydronic Baseboard)			
Minimum	-	-	-
Maximum	-	-	-
Western			
Core (Natural Gas Boiler)			
Minimum	-	8 (Coal)	8 (Peat)
Maximum	-	11 (Oil)	22 (Coal)
Intermediate (Natural Gas Hydronic Baseboard)			
Minimum	-	-	-
Maximum	-	-	5 (Coal)
Residential (Natural Gas Hydronic Baseboard)			
Minimum	-	-	-
Maximum	-	-	-

the total levelized cost of district heating including subscriber system, distribution system and heat plant costs for various plant sizes and fuels. Where positive benefits exist, both the minimum and maximum benefits, in percentage terms, are indicated.

These results indicate that district heating is most attractive in areas with relatively high cost conventional heating alternatives and high heat load densities. In addition larger station sizes, where economies of scale are most significant, improve the attractiveness of district heating.

152 SENSITIVITY ANALYSES

Sensitivity analyses to assess the impact of changes in major study assumptions on the results of the economic analysis were carried out on a number of study variables including:

- (i) discount rates used to compute present value
- (ii) greenfield installation capital costs
- (iii) the use of cogeneration rather than heat only plants
- (iv) market penetration

The primary analysis was carried out using a five per cent real discount rate. Sensitivity analyses using discount rates of three and seven per cent were conducted on the Atlantic Region cases in order to determine the impact of varying costs of capital on the economic viability of district heating. The analyses showed that a reduction in the discount rate from five to three per cent had a positive impact on the economic attractiveness of district heating while increasing the discount rate from five per cent to seven per cent had a negative effect on district heating. These results reflect the higher level of capital investment associated with the installation of a new DH system and retrofitting of existing subscriber heating equipment to accomodate district heating as compared to continuing in the use of the least cost conventional heating alternative.

The primary analysis was also based on serving the heating needs of existing commercial buildings and housing stock with district heating. In this analysis many of the capital costs of the existing subscriber heating systems were considered to be essentially sunk costs and were excluded in cost comparisons with district heating. In addition, the capital costs of installing a DH distribution system in built-up areas and retrofitting existing buildings to accept district heating, in many cases, results in higher capital costs for district heating than would be expected in an entirely new development or greenfield situation. Sensitivity analyses were carried out, again using Atlantic Region pricing regimes, to examine the economic feasibility of district heating in a greenfield situation. Two cases were examined. In the first case, district heating was compared with electric baseboard heating as in the primary analysis. In the second case, recognizing that in a greenfield situation the method of utilizing conventional energy forms might change, district heating was compared with natural gas using a high efficiency condensing type furnace. The analysis showed that the benefits of district heating as compared to electric baseboard heating are enhanced for the larger station sizes in the greenfield situation. However, when compared to natural gas (assuming availability of gas from the Venture gas Field) burned in a condensing type furnace no benefit is achieved with district heating.

The cost of heat in the primary analysis was based on heat only stations. Heat can also be produced in conjunction with the production of electricity in cogeneration plants. Sensitivity analyses were carried out, based on the Central Region energy pricing regime, to examine the impact of cogeneration on the economic feasibility of district heating.

For purposes of these analyses, two values were used for the value of electricity produced in a cogeneration plant: $0.033/kWh and $0.060/kWh. The analysis indicated that the credit for electricity at $0.033/kWh was insufficient to recover the additional costs associated with cogeneration relative to the heat only plant. A credit of $0.06/kWh for electricity produced from a cogeneration plant, however, improved the economics of district heating for the larger plant sizes. It should be emphasized that these cogeneration sensitivity analyses were based on the installation of new multiple unit cogeneration plants and the sale of cogenerated electricity to electric utilities typically at fuel or energy displacement value. To the extent that existing facilities could be retrofitted for cogeneration at lower capital costs, and/or electrical output could be sold directly to subscribers at a price above the electric utilities' fuel or energy displacement value, the economics of cogeneration/district heating would improve.

The sensitivity analyses on market penetration are dealt with in the discussion on the opportunities for district heating.

153 OPPORTUNITY ANALYSIS

Using the results of the economic analysis and the heat load characteristics estimated for the "Canadian Model" discussed in section 133 above, a preliminary analysis of the potential for district heating for each of the three geographic regions considered in the study has been carried out.

The useful heat requirement for each city in the Atlantic, Central and Western Regions listed in Table 1-4 was estimated based on its population and the appropriate estimated per capita heat consumption based on degree days as indicated in Table 1-5. The total useful heat requirement for each city was then allocated among the various heat load densities shown in Table 1-5: the core; 200 MJ/m^2 and above (excluding the core); 100-199 MJ/m^2; and 0-99 MJ/m^2. This latter heat load density was not considered large enough to support district heating and therefore was excluded from the analysis.

The allocated heat requirements were then used to determine the heat plant size for each city required to serve:

(i) all heat loads equal to or greater than 100 MJ/m^2 (residential, intermediate and core heat loads);

(ii) all heat loads equal to or greater than 200 MJ/m^2 (intermediate and core heat loads); and

(iii) core heat load only.

The approach assumed a single heat plant (up to a maximum size of 300 MW) serving a city or town and no provision was made for transmission requirements. To the extent that it was considered impractical to service a heat load concentration from a single source located close to the load center, this could reduce the potential for district heating. As discussed earlier the analysis was carried out on two bases. In one case some of the economic benefits of district heating in high load areas were used to subsidize the cost of serving lower heat load density areas. Such cross-subsidization would be expected to increase the estimate of the heat requirement that could be served by district heating. In the other case no cross-subsidization between core, intermediate or residential heat loads was assumed. This latter analysis would be expected to provide a "lower limit" estimate of the heat requirement that could be served by district heating.

TABLE 1-7

Regional Opportunity Analysis
(With Cross-subsidization)

Region	Population(1)	Annual Heat Consumption(2)	Economically Attractive for District Heating			
			100% Penetration		50% Penetration	
			Energy	Percent	Energy	Percent
	(000's)	10^6GJ	10^6GJ		10^6GJ	
Atlantic	546	24.72	11.22	45	2.49	10
Central	9103	410.54	203.62	50	49.22	12
Western	3442	163.67	80.64	49	10.65	7
Total	13091	598.93	295.48	49	62.36	10

Notes: (1) Population of cities listed in Table 1-4 for each region.

(2) Useful heat consumption of the cities in Table 1-4.

The analysis and results of the "cross-subsidization" case are discussed below. Using the heat plant sizes and interpolating from the unit heat plant costs determined in the economic analysis, it was possible to determine which fuel types, if any, would, for these plant sizes, result in a total levelized cost of district heating including retrofit costs less than the weighted average least cost of continuing to serve the mix of residential, intermediate or heat loads noted above by conventional heating alternatives. The results of the regional opportunity analyses on this cross-subsidized basis are presented in Table 1-7.

As can be seen from the table, centers containing a population of 13.1 million, out of total Canadian population of 24.3 million at the time of the 1981 census, were considered in the analysis. It is estimated that the total requirement for useful heat for residential and commercial space heating and domestic hot water for these population centers is about 600 PJ per year. If one assumes an overall average conversion efficiency of 60 per cent for the conventional systems presently supplying this load and adjusts for population, this results in an estimated heat input requirement for space heating and domestic hot water for the residential and commercial sector in Canada of about 1850 PJ per year. This estimate compares reasonably well with the actual total energy consumption recorded for these sectors in 1981 of about 2100 PJ as indicated in Figure 1-2, particularly when one recognizes that this latter figure includes some energy consumption for process purposes, electrical appliances and lighting.

The table indicates that in the Atlantic Region, with 100 per cent market penetration, district heating could economically supply about 11.2 PJ of useful heat or about 45 per cent of the annual space heating and hot water requirements of the eleven cities and towns in the region that passed the initial screen. While about 45 per cent of this potential or about 5 PJ is associated with the region's two largest centers, economic feasibility is fairly broadly based with district heating estimated to provide some economic benefit in virtually all centers. Sensitivity to market penetration is demonstrated by the fact that with only 50 per cent market penetration, the amount of useful heat that could be economically supplied by district heating would be reduced to 2.5 PJ or 10 per cent of the region's requirements. This occurs because the reduced load, associated with reduced market penetration, results in smaller heat plant sizes, loss of economies of scale, and a consequent increase in unit heat costs.

Results in the Central Region are in percentage terms somewhat higher for the 100 per cent market penetration case than the Atlantic Region with district heating appearing economic in the supply of 204 PJ or 50 per cent of the region's requirements. Economic potential, however, is much more heavily concentrated in the larger centers. District heating appears economic in only the 14 largest centers of the total of 48 cities and towns in the region included in the analysis and the two largest centers represent about 77 per cent of the total potential. Similar to the Atlantic Region, 50 per cent market penetration of district heating results in a substantial reduction in the proportion of the region's residential and commercial heat requirements that can be economically served by district heating.

Results in the Western Region are similar to the Central Region both in percentage terms and in the concentration of economic potential for district heating in the seven largest of the 16 cities and towns in the region included in the analysis. The concentration of potential for district heating, primarily in the largest centers in the Central and Western regions, occurs because of the availability of low cost natural gas. The availability of this low cost conventional energy form more than offsets, for all but the largest centers, the greater potential for economies of scale available to district heating. This follows from these regions having more large population centres than the Atlantic Region.

The use of the weighted average least cost of serving the mixed heat loads by conventional means to determine economic feasibility results in cross-subsidization among heat load types. As indicated in Table 1-6, the economic benefits of district heating for residential and intermediate heat loads, particularly in the Central and Western regions, are modest or non-existent. Cross-subsidization by the core heat loads (which reduces the economic benefit to the core heat loads) to offset the costs of serving a marginally uneconomic intermediate or residential heat load increases the total heat load that could be economically served by district heating. However it also tends to reduce the benefits of district heating to breakeven with the least cost conventional heating alternative. If the decision to convert to district heating is based solely on economic grounds, then, with marginal or no economic incentive for conversion, the methodology of the foregoing opportunity analysis likely produces an estimate of the maximum potential for district heating.

The alternative opportunity analysis, in which there is no cross-subsidization assumed, can be carried out in the same manner as the method just discussed except that instead of comparing levelized heat plant costs to the weighted average least cost of serving the mixed heat loads by conventional means, levelized heat plant costs would be compared to the least cost method of serving each individual heat load type (residential, intermediate and core) by conventional means. This approach eliminates entirely any element of cross-subsidization among the three heat load types.

The results of the opportunity analysis carried out on this basis are presented in summary form in Table 1-8. It can be seen from the table that this approach greatly reduces the economic potential for district heating compared to the opportunity analysis with cross-subsidization. In the case of the Central and Western regions, residential heat loads are eliminated entirely. Similar to the opportunity analysis with cross-subsidization, the results in all

TABLE 1-8

Regional Opportunity Analysis
(Without Cross-subsidization)

Region	Population(1)	Annual Heat Consumption(2)	Economically Attractive for District Heating			
			100% Penetration		50% Penetration	
			Energy	Percent	Energy	Percent
	(000's)	10^6GJ	10^6GJ		10^6GJ	
Atlantic	546	24.72	7.62	31	1.18	5
Central	9103	410.54	104.91	26	22.49	6
Western	3442	163.67	37.10	23	7.49	5
Total	13091	598.93	149.63	25	31.16	5

Notes: (1) Population of cities listed in Table 1-4 for each region.

(2) Useful heat consumption of the cities in Table 1-4.

three regions are highly sensitive to the level of market penetration achieved by district heating. At 100 per cent market penetration, it is estimated that district heating could competitively supply about 25 per cent of the space and domestic hot water heating requirements of the cities and towns considered in the analysis. If district heating is only able to achieve 50 per cent market penetration this estimate reduces to about 5 per cent of space and domestic hot water requirements.

It would appear, however, from the results of the economic analysis that there is likely some opportunity for cross-subsidization in the Atlantic Region and to a lesser extent, in the Central and Western Region. Thus the results of the opportunity analysis without cross-subsidization are likely an estimate of the minimum potential for district heating within the context of the assumptions used in the study.

Any attempt to estimate the extent to which cross-subsidization could be used to increase the potential of district heating above these lower values, would require site specific evaluations which are beyond the scope of this study. However the two approaches to analyzing the potential for district heating in Canada would appear to provide reasonable estimates of the upper and lower limits for its potential.

1.6 INSTITUTIONAL BARRIERS AND INCENTIVES TO DISTRICT HEATING

It is clear from the opportunity analysis that the potential for district heating in all regions of Canada is very much dependent on the level of market penetration that the technology is able to achieve. Consequently, it is important to consider some of the non-economic institutional issues that may prevent a high level of market acceptance and identify the benefits of district heating that can be used as incentives to overcome these institutional barriers.

161 SUBSCRIBER ATTITUDES

The Canadian public has very little knowledge of district heating. Consequently, district heating faces the normal resistance to change that confronts any new technology. However, due to the characteristics of the technology and the fact that it is an energy technology, district heating is likely to encounter greater than normal consumer resistance. District heating is a capital intensive technology that requires substantial front-end investment, not only on the part of the developer, but also on the part of the subscriber to replace or retrofit existing heating systems. In addition to the front-end capital investment, the subscriber retrofitting to a DH system will be faced with the inconvenience and disruption associated with the actual installation of the distribution system and the retrofitting of the existing individual heating system. This disruption can also contribute to consumer resistance, particularly for commercial customers who may be temporarily prevented from conducting their businesses.

While the potential subscriber is virtually assured that he will experience the front-end costs and inconvenience of connecting to a DH system, the benefits are perceived to be somewhat less certain since they are typically based on extended payback periods and projections of the future cost of alternative energy sources. The demonstrated inability by all levels of government to predict the future availability and cost, even of indigenous energy resources, has made Canadians understandably skeptical and reluctant to participate in energy solutions that require substantial up-front capital commitments, in order to obtain long-term future benefits in energy costs.

In the face of present energy surpluses and an emerging expectation that these surpluses will continue in the future, the economic incentives to become more energy efficient and the penalties for lack of progress in this area are diminishing. Canadians are more inclined to take a "stand pat, wait and see" attitude towards the introduction of new capital intensive energy technologies.

If district heating is to gain market acceptance in Canada's increasingly competitive space heating market, potential subscribers must first be confident that the technology offers an assured supply of reliable and competitively priced thermal energy over the long term. Subscribers must also be encouraged to base their heat source decisions on life-cycle costs rather than low capital costs or short-term payback periods. The developer must create confidence that it has the technical and financial resources to develop a stable fuel source, together with an operating system and organizational structure, capable of producing and delivering thermal energy with a level of convenience and reliability of supply exceeding that of traditional individually owned and operated systems. In addition, one of the more significant barriers to subscriber acceptance - the burden of retrofitting existing buildings - must be minimized for potential subscribers who generally have limited access to capital, either through tax incentives or conversion grants or, by providing favourable financing and/or creating a pricing formula for district heating which tends to offset retrofit costs when compared to alternative heating costs.

To the extent that credible economic analysis supports the development of district heating and that innovative financing and energy pricing can be developed to offset the disincentives to implementation created by connection and retrofit costs, the problem then becomes one of effectively disseminating this information, along with information on the other benefits of district heating, to potential subscribers in a readily understood format. This is a marketing problem which, due to the site specific nature of most DH projects, is likely to require a marketing plan which is, for the most part, tailored to the economic and other benefits of that particular project rather than the use of mass marketing approaches that are suitable to conventional space heating technologies.

Nevertheless, government agencies could play a valuable role in this regard through broad information programs directed at creating a general awareness of the technology among the Canadian public.

162 DEVELOPER ATTITUDES

The potential investor or developer of a DH project will be as concerned as the potential subscribers, with the volatility of energy prices that has been exhibited in the past and the high level of uncertainty associated with long-term forecasts of energy prices. However, the relative cost of alternative energy sources is not the only factor likely to threaten the economic feasibility of district heating. The developer will require a significant initial and continuing subscriber heat load over which to distribute the relatively large fixed costs associated with the capital investment in the system. In this regard, developers would likely favour a mandatory hook-up policy or long-term heat supply contracts in order to transfer some of the financial risk of the DH project to the subscribers. It is unlikely, however, that a mandatory hook-up policy would be acceptable in Canada where individuals have historically been free to choose, within the limits of requirements for public safety and environmental considerations, whatever heat source was accessible to them. Furthermore, long-term heat supply contracts are also not likely to be acceptable to potential residential, commercial, or industrial subscribers since similar commitments are typically not required by competing conventional energy sources. This is an area where significant support for DH projects could be provided by all levels of government through commitments to connect government facilities on a long-term contractual basis to DH systems.

A developer will require long-term franchise and expropriation rights in order to be assured that such long-range development plans could proceed without future interruption. These rights are normally granted to regulated public utilities in return for accepting the constraints and obligations of regulation. Fear of regulation is cited in a number of U.S. studies as one of the more significant deterrents to private investment in district heating since the distribution of heat through a DH system is not a natural monopoly as is, for example, the distribution of electricity. Electricity is a product for which, for many subscribers, there is no practical substitute and therefore little competitive pressure. Subscribers to district heating, however, do have a number of alternatives and, consequently, district heating would be subject to substantial competitive market forces. Consequently, private developers would likely be reluctant to expose themselves to a regulatory system which could force them to invest capital to extend service to marginally economic customers and, at the same time, could limit returns on capital to levels which, in the light of significant competitive and financial risks, would be considered unacceptably low.

In this regard, existing energy utilities are probably among the best equipped organizations to deal with many of these concerns in the implementation of district heating. Such utilities typically operate capital intensive systems with long-life assets and extended pay-back periods. Due to their continuing need for capital, they have established their credit worthiness in the financial markets and thus have reasonable access to the longer term financing that is required to produce a reasonable return on capital intensive projects. Utilities also work with the longer planning horizons that are required in the development of district heating and have developed, in operating their current line of business, many of the administrative, organizational and technical capabilities required to cope with the regulatory and operating requirements of a DH system. In certain circumstances electric utilities might also offer an economically attractive heat source through the operation of cogeneration plants. However, to the extent that district heating, natural gas and electricity might be in direct competition in many areas, significant involvement of an established energy utility in DH projects raises concerns of conflict of interest which might operate to impede the development of district heating.

Municipal governments also possess many of the attributes necessary to overcome a number of the institutional barriers to district heating. Questions of franchise areas or access to right-of-way would not concern a municipal owner. Like utilities, most large municipalities are experienced in long range planning, normally have reasonable access to capital and have less demanding rate of return on investment objectives than the private sector although, as a minimum, debt issued for a DH project would normally be expected to be self-supporting. Through the operation of normal services, such as water distribution and sewage systems, many municipalities have already developed the skills and resources necessary to operate a DH system. As discussed earlier, municipal governments have played a major role in the development of district heating in many parts of Europe and are one of the driving forces behind the renewed interest in district heating in the United States. For many municipal governments in the U.S., district heating has been considered a means to an end rather than an end in itself. For example, district heating may be viewed by a municipality as part of the solution to a municipal solid waste problem, a method of encouraging urban renewal or attracting industry by exploiting a local low cost energy source.

163 FINANCIAL CONSIDERATIONS

The large initial capital requirements and risks associated with district heating may constitute a significant barrier to the financing of a proposed DH project. The perceived "newness" of the technology, particularly if based on a non-conventional fuel source, its capital intensive nature, long pay-back period and the substantial competitive pressures to which the project would be exposed all serve to increase the perceived riskiness of district heating in the minds of potential investors and lenders.

Ownership of the project by entities such as utilities or municipalities having relevant related experience, established credit worthiness, reasonable access to capital and possibly government guarantees would serve to reduce risk.

Construction contracts based on firm lump sum bids would serve to transfer some of the construction risk from the developer/lender to the contractor. Firm, long-term "all events" heat supply contracts with large, creditworthy customers would shift much of the financial and business risks of a DH project from the owner to its customers. Acceptance of long-term, all-events, cost-of-service type heat delivery contracts for large government owned facilities could significantly enhance a DH project since viability in project financing is often a function of the enforceability of "all-events" contracts with the project's customers and the credit worthiness of these customers.

164 COMPETING ENERGY FORMS

As noted earlier, established energy forms are typically offered to Canadian consumers at their average cost of production which is often below the long-run marginal costs of supply. District heating, as a new heat source, must install and develop its system at current costs, which places district heating, or any new energy technology, at a significant economic disadvantage.

Looking at the supply/demand situation of conventional energy forms, total Canadian domestic and export sales of natural gas have remained relatively static in recent years at about 2800 PJ per year while additions to reserves have averaged almost 5000 PJ per year. While much of the resulting surplus has received export approval, increasing indigenous U.S. supplies, declining demand and high Canadian prices have resulted in actual exports falling below authorized levels. In domestic markets, growth in demand has been slow due to a relatively weak economy and increasing energy efficiency. Given this situation, the National Energy Board is currently projecting an excess supply of natural gas until the turn of the century and possibly beyond. Electricity demand growth has also slowed considerably in recent years with the result that existing, and committed generating capacity, is substantially in excess of current requirements and this excess is expected to persist into the 1990's. As a result of the abundant supplies of both natural gas and electricity there has been intense competition between these two fuels, particularly in Central Canada for oil's remaining market share. The energy environment described is a very different one, and one much less hospitable to potential DH projects than the environment anticipated only four or five years ago. During that period, substantial increases in conventional energy costs were expected and there was a perceived need to preserve high-grade fuels such as gas and oil for industrial feed stock and transportation purposes.

165 TECHNOLOGICAL FACTORS

Technological factors such as efficiency, reliability and flexibility of fuel types generally favour centralized heat generation for community use rather than dispersed individual home and building heating systems. The only major technical problem associated with district heating to be overcome is the development of a small inexpensive heat meter. To date, such heat meters have been expensive, and billings to DH consumers have been computed, not by individual consumption, but by a proportional share of group consumption. However, it must also be stated that such billing methods have not created any real problem in Europe as long as district heating has been more economical than individual home heating.

On the positive side, district heating can lower overall fuel consumption for the same subscriber requirements because its overall conversion efficiency is higher than the conversion efficiencies of conventional systems. It is possible to get a sense of the potential order of magnitude of this benefit by considering the opportunity analysis for the Atlantic Region. The analysis indicates that an estimated 11.2 PJ per year of useful heat could be economically supplied by district heating assuming 100 per cent market penetration and cross-subsidization. The overall efficiency of the DH system would be in the range of 80 per cent assuming the use of a conventional fossil fuel such as heavy oil or coal. On this basis, district heating would require 14 PJ of fossil fuel to serve the load. A review of Table 1-3 indicates that heat load is served largely by oil and to a lesser extent electricity. If one assumes on the basis of Table 1-3 that 70 per cent of the heat is supplied by oil at an average conversion efficiency of 60 per cent and the remaining 30 per cent of the load is met by electricity, of which 50 per cent is supplied by fossil fuel generation (the balance by nuclear and hydro sources) at a conversion efficiency of 33 per cent, then 18 PJ of fossil fuel would be required to meet the load of 11.2 PJ of useful heat from conventional sources. Thus the requirement for fossil fuel for conventional heat sources is some 30 per cent greater than the fossil fuel requirement for district heating.

Using similar assumptions and recognizing the change in mix between fossil fuels and electricity (and the fact that a higher proportion of electricity is generated from non-fossil fueled sources), it is possible to roughly estimate the fossil fuel that could be conserved in the Central Region. District heating would require about 255 PJ of fossil fuel to provide the 204 PJ of useful heat requirement that is estimated could be economically served by district heating assuming 100 per cent market penetration. About 300 PJ of fossil fuel would be required to meet this load from conventional sources, about 15 per cent more than for district heating. Similarily, in the Western Region, district heating would require about 101 PJ of fossil fuel to provide the 81 PJ of useful heat requirement that is estimated could be economically served by district heating assuming 100 per cent market penetration. About 130 PJ of fossil fuel, some 28 per cent more than for district heating would be required to meet this load from conventional sources. The estimated annual total saving of fossil fuel due solely to the increased conversion efficiency of district heating is about 78 PJ or about 12.40 million barrels of oil equivalent per year.

In addition, to the extent that low grade fuels (which would not otherwise normally be utilized) such as wood, peat, municipal or industrial waste, or waste heat were utilized, the reduction in the consumption of high grade conventional fossil fuels would be even larger.

166 ENVIRONMENTAL FACTORS

Few generalizations are possible with regard to the environmental barriers to, and incentives for, district heating since the environmental impact (positive or negative) is dependent on the type of conventional fuel or energy form that is being displaced and the type of fuel that is being consumed in the DH station. To the extent however, that high grade fuels consumed in individual heating systems are replaced with similar fuels consumed in a central heat plant, the environmental impact will normally be positive. However, district heating is more typically viewed as a heat load for the use of low grade fuels. To the extent that low grade fuels displace high grade fuels consumed in individual systems, the environmental impact of district heating could be negative.

167 GOVERNMENT POLICY

This study has indicated that district heating appears to be an economically competitive method of providing space heating in larger urban centers across the country, notwithstanding general expectations of constant real prices or even negative real price changes in competing conventional energy forms for the intermediate and long-term future. The study results also indicate, however, that the economic feasibility of district heating is dependent on it achieving a very high level of market penetration. A reduction in market penetration from 100 per cent to 50 per cent is estimated to reduce the economic potential for district heating by about 80 per cent due to lost economies of scale. Consequently, non-economic institutional barriers and consumer "inertia" that limit the level of market penetration could have a dramatic impact on the economic potential for district heating.

It is unlikely that district heating could achieve the high levels of market penetration required to maximize the economic benefits of the technology without the significant support of all levels of government. However, as mentioned earlier, federal government initiatives in the energy sector have, in recent years, been oriented more towards promoting energy conservation and reducing oil consumption than to promoting the use of specific energy forms. Provincial governments have tended to promote the use of energy resources indigenous to their province and municipal governments have generally not played a major role in attempting to influence the energy consumption habits of their constitutents. In addition, with the recent development of surpluses of natural gas and electricity, it is not clear to what extent the conservation of these high grade energy forms remains a priority with government.

To the extent, however, that the conservation of high grade fuels and energy forms continues to be a long-term objective of government, the ability of district heating to make a significant contribution towards this goal may be the incentive required for federal and provincial governments to adopt a positive stance towards the technology. As discussed earlier, district heating does offer significant potential for energy conservation due to improved conversion efficiency relative to conventional individual heating systems. To the extent that low grade fuels such as coal, wood, peat or municipal solid waste burned in a DH plant can be substituted for oil, gas or electricity consumed in individual heat plants, even greater conservation of high grade fuels can be achieved.

Potential benefits to municipalities which would induce them to promote the development of district heating range from:

(i) providing a solution to the problem of disposing of municipal solid waste;

(ii) providing a focus for urban development and renewal;

(iii) increasing local employment opportunities through the development of a heat load for local low grade energy resources;

(iv) increasing economic activity within the region by retaining consumer expenditures for spacing heating requirements within the local economy; and

(v) increasing the attractiveness of the municipality as a place to live and work due to the availability of low cost heat.

European experience, and more recently, U.S. experience indicates that municipal governments have played a pivotal role in the development of district heating. As noted earlier, the role of Canadian municipal governments in the energy sector has, with some notable exceptions, been relatively modest. If district heating is to develop in Canada, federal and/or provincial governments must create an awareness at the municipal level of district heating and the significant direct and indirect benefits that the technology can offer to municipalities. The objective of such an information program would be to encourage municipalities to assume, as they have in other countries, a leadership role in the promotion and development of the technology. Without the active and enthusiastic support of municipal government, it is unlikely that district heating could achieve the level of market penetration necessary to make it economic.

Municipalities should also be encouraged to engage in the development of long-term energy plans for their communities, on a basis similar to the type of regional and municipal energy planning that is carried out in many European communities. Such plans would not carry the force of law as they do in some countries in Europe however, they could be used to ensure that individual low grade fuel energy projects within the community, were implemented in such a manner that they could ultimately be connected and integrated into a single multiple source heat system.

There is also a need to increase the awareness of district heating among the general public. As noted earlier, marketing programs designed to outline the benefits of district heating in quantitative terms will likely have to be tailored to specific projects. Central governments however, could play a valuable role in increasing general awareness and credibility in alternative energy technologies (such as district heating) and their potential benefits through the development and distribution of informational material to the general public.

In addition to efforts to increase general awareness of district heating, there are a number of ways in which government can provide direct support for district heating.

Governments at all levels are owners of, and tenants in significant amounts of commercial office space. A policy of connecting government owned facilities, and favouring the leasing of commercial office space from buildings connected to DH systems could go a long way to providing DH projects with the important initial major baseload customers necessary to make them economically and financially viable.

Financial assistance will also likely be necessary for both developers and subscribers of district heating if high market penetration levels are to be achieved. This assistance can take a variety of forms and would likely include:

(i) financial support for DH feasibility studies, particularly for cities and towns having the attributes likely to favour district heating;

(ii) favourable tax treatment of private investment in DH distribution and end-use systems; and

(iii) assistance in project financing, both through grants and provision of low interest loans.

All of the above types of assistance have been offered in the United States to promote the development of district heating and were employed, for example, in the cases of St. Paul and Trenton to assist in financing the study and construction of their respective hot water DH systems.

Finally, and perhaps most importantly from the point of view of maximizing market penetration, financial assistance will be required to assist the subscriber in dealing with the cost of retrofitting existing building stock to district heating. This assistance, provided either directly by government, or indirectly through the developer could take the form of:

(i) favourable tax treatment of investment in subscriber systems;

(ii) grants to offset the cost of retrofit; or

(iii) low interest loans, with repayment schedules related to the savings in energy costs. The objective of such loans could be, for example, that the total cost of district heating to the subscriber, including loan amortization, would not exceed his cost of heating with his existing system.

PART TWO

INTRODUCTION

2.1 GENERAL

District Heating has enjoyed wide acceptance in many countries in Europe where the technology is considered to provide substantial economic benefits compared to individual heating systems. There are, as well, a number of other benefits, not entirely of an economic nature that are associated with district heating and accrue to individual consumers or society as a whole. Some of the major benefits are:

(i) energy conservation through the use of central heating plants which are generally more efficient than individual heating installations;

(ii) conservation of the high grade fuel or energy forms (natural gas, oil, electricity) normally consumed in individual heating systems through the substitution of low grade fuels such as coal, wood or municipal solid waste which can only be practically utilized in larger central heat stations;

(iii) greater fuel substitution flexibility since neither the distribution network nor subscriber heat installations of a district heating system are affected by a change in fuel type at the central heating plant;

(iv) greater security of heat supply since the central heat station is normally designed and built with allowances for reserve or back-up capacity which are impractical for the majority of individual heating systems;

(v) district heating can, in certain circumstances, reduce the level of particulate and gaseous emissions released into the atmosphere, as well as the level of thermal pollution.

In view of the benefits associated with district heating and the limited acceptance that the technology has enjoyed in Canada, Energy, Mines and Resources, Canada commissioned a study to determine the realistic potential for the development of district heating in this country. The objectives of the study were to:

(i) Review and document recent work in Canada relating to district heating;

(ii) Establish the realistic potential for district heating in Canada and determine the general circumstances and conditions necessary to realize potentials which exist.

(iii) Document the development of district heating in countries in which the technology is well entrenched and explain how and why this was achieved.

(iv) Identify the principal barriers to implementation of district heating and suggest means for their resolution.

(v) Identify and quantify the principal benefits that may be realized by both the public and private sectors as a result of the successful deployment of district heating.

Following requests for and review of proposals, the study was awarded to Monenco Consultants Limited (formerly known as Montreal Engineering Company, Limited). The study has been carried out in association with DHM Energy Consultants Ltd., K-Konsult of Sweden, and Cogeneration Associates Limited. A brief outline of the organization and contents of the report are presented below:

Part 1 - Summary and Conclusions

Part 1 provides a summary of the study findings and conclusions. It has been prepared in a manner which would allow its distribution independent of the main body of the report. Consequently the discussion and amount of background material contained in the summary is more extensive than would otherwise be the case.

Part 2 - Introduction

Part 3 - General Description of District Heating Systems

The purpose of Part 3 of the report is to provide the reader with a very brief overview of the basic components and characteristics of district heating systems.

Part 4 - District Heating Experience

Part 4 discusses the development and history of district heating in the United States and Europe with specific reference to Denmark, Sweden, the Netherlands, and Germany. It also discusses the status of district heating in Canada.

Part 5 - The Canadian Environment

Part 5 of the report discusses the environment in which district heating must compete in Canada. Climatological, demographic and competitive factors are considered. The objective of this part the study is develop a general "Canadian Model" of the heat load characteristics of cities and towns for use in the study opportunity analysis.

Part 6 - Energy Supply Systems

Part 6 contains a comprehensive discussion of the various fuel types, heat sources, and heat plants that may have application as sources of heat for district heating systems.

Part 7 - Transmission and Distribution Network

Part 7 of the report describes the characteristics of district heating transmission and distribution sytems, the more important design considerations, and the effect of heat density, connection density, and market penetration on costs.

Part 8 - Subscriber Heating Systems

Part 8 of the report discusses district heating end-user systems and compares them to conventional heating systems. It also discusses retrofitting of district heating end-user systems to different types of existing building stock.

Part 9 - Economic Analysis

Part 9 of report examines the economic feasibility of district heating for a variety of heat load densities under varying climatological and competitive pricing regimes. In addition a methodology is developed to provide a preliminary estimate of the potential for district heating in Canada.

Part 10 - Environmental Considerations

Part 10 of the report provides a basis for estimating the likely impact (positive or negative) of developing district heating using a variety of different fuels to displace energy supplied by conventional heating systems.

Part 11 - Barriers and Incentives for District Heating

Part 11 discusses the various non-economic factors that may impede or serve as a catalyst to the development of district heating. Topics discussed include subscriber attitudes, developer attitudes, regulatory aspects, financial considerations, competing energy forms, technological and environmental factors and government policies.

PART THREE

GENERAL DESCRIPTION OF DISTRICT HEATING SYSTEMS

PART THREE

GENERAL DESCRIPTION OF DISTRICT HEATING SYSTEMS

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3.1 GENERAL

There are many definitions of district heating. The International District Heating Association (IDHA) describes district heating as a method by which thermal energy from a central source is distributed to residential, commercial and industrial consumers for use in space heating, water heating, and process heating. The Swedish District Heating Association describes DH systems as systems with potential for expansion and in which municipalities have administrative and financial interests. In Denmark, both municipally-owned and cooperative heating and distribution systems capable of expansion are referred to as DH systems. The French term for district heating is Chauffage Urbain indicating that it is associated with the centralized production and distribution of heat in cities.

For purposes of this study the IDHA description is probably most suitable since it is not contingent upon municipal participation. This definition encompasses not only relatively small systems such as group heating projects or "block centrals" but also very large systems which may serve an entire city.

All DH systems consist of three major components:

- the heat plant;
- the transmission and distribution systems; and
- the subscriber systems.

Each of these components is discussed in greater detail in following parts of the report; however, a brief description of the function of each may be useful in order to obtain a general overview of the physical characteristics of a DH system.

3.2 THE HEAT PLANT

The heat plant may consist of any combination of heat-only units, units which produce both heat and electricity called cogeneration units, waste heat recovery units, and auxiliary heat units for standby and peaking purposes. The units are not necessarily located at a single site but rather may provide heat to the system from a number of locations. Heat units produce heat for the transmission and distribution systems in the form of either steam or hot water.

In the case of steam, the pressure is usually between 700 - 1,400 kPa. Both lower and higher pressures can be used however, depending on customer requirements, and the size and pressure rating of the transmission and distribution piping and equipment.

Hot water district heating systems usually fall into three temperature categories - low, medium, and high temperature. It is common practice to vary the supply temperature for each category according to the heating demand, however, the maximum supply temperatures are approximately 90°C, 120°C and 200°C respectively.

If the heat source is a cogeneration plant, it will consist of steam generators supplying high pressure steam to either extraction or back pressure turbines.

An extraction turbine has openings in turbine casing(s) or cross over connection between the high and low pressure turbines for the extraction of steam. Extraction turbines are required when the distribution network uses steam or HTHW and the location of the extraction ports will depend upon the pressure and temperature requirements of the steam distribution network. If the distribution network uses HTHW, the steam must be extracted at a temperature level suitable for heating the HTHW through a heat exchanger.

A back pressure turbine consists of a conventional turbine with the steam exhausted from the outlet of the low pressure turbine. When no heat is required, the turbine unit can be operated as a condensing turbine unit to increase the electrical production. The back pressure turbine must be designed and operated to provide steam at a temperature level and quantity, commensurate with the heat exchanger characteristics and the variable requirements of the distribution network.

If the distribution system heat transfer fluid is steam and the unit is for heating only, the steam is produced by a steam boiler at whatever pressure is necessary for the system. If the distribution system heat transfer fluid is hot water, the unit may be a hot water or steam generator. With a hot water generator the water can be delivered directly to the distribution network (one circuit) or the heat plant system can be a two circuit operation, transferring the heat through heat exchangers to the distribution system water. When a steam generator is used, the heat can be delivered to the distribution network only through a heat exchanger. There are general factors to be considered when selecting steam or hot water generators. These factors are discussed in more detail in Part 6.3 of the report.

3.3 THE TRANSMISSION AND DISTRIBUTION SYSTEMS

The transmission system is the initial part of the heat distribution network. It usually consists of a pair or several pairs of trunk pipelines to transmit the heat transfer fluid from the heat plant to the distribution network and return it to the heat plant. If the heat plant can be built close to the heat loads, the transmission system will be of minimal length. On the other hand, if the plant is located at some distance from the heat loads, the length of the transmission system can be greater than the length of the distribution system. Transmission and distribution piping systems are insulated and may be direct buried, placed in underground metal or concrete conduits, culverts or tunnels. In some instances the systems are run above grade, although this is less common, particularly for distribution piping.

There is essentially no difference in the pipe systems used for the transmission and distribution systems. However, unit costs for the transmission system are generally less than for the distribution network since there are few connections and in most instances the transmission system is located in open areas.

When the heating fluid is steam, a good transmission system consists of steam and condensate lines running side by side. For most existing systems, the condensate pipe is either no longer in service due to pipe failure or it was never installed. Due to pipe corrosion and failure, with resulting loss of the steam condensate, condensate return is a costly problem inherent to steam systems.

The class of construction required for steam and HTHW systems is usually extra heavy pipe and fittings due to the high temperature and pressure. Consequently material and installation costs for these types of distribution systems can be very high compared to the medium temperature hot water (MTHW) and low temperature hot water (LTHW) systems. Furthermore, the temperature of steam and HTHW systems is much higher than is acceptable for polyurethane insulation and hence, a different type of insulation and installation process is required. Therefore, the insulation for such systems will cost more than the factory applied polyurethane insulation which is suitable for the LTHW and MTHW systems.

In order to increase its reliability the distribution system should be installed in a loop pattern with interconnecting links and valves to enable any point on the system to be isolated for maintenance or repair with minimal service interruption to the rest of the system.

3.4 THE SUBSCRIBER SYSTEM

In the early days of steam DH system, steam was supplied directly to building heating systems through a pressure reducing station. The steam was condensed in heating coils and convectors and the condensate often discharged to the sanitary waste. This type of heat supply to buildings was replaced in the fifties and sixties with steam/water and steam/air heat exchangers. The building heating system was supplied with hot water heated through the heat exchanger. Even with this type of system, it was not uncommon to supply steam directly to some of the air handling unit heating coils to reduce the capacity of the heat exchanger required. If all of the steam supplied to a building were passed through a steam/water heat exchanger and the building heated with a secondary hot water system, then the subscriber system for steam or hot water DH systems would be essentially the same.

PART FOUR

DISTRICT HEATING EXPERIENCE

PART FOUR - DISTRICT HEATING EXPERIENCE

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FIGURE

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4-2 Gross Investments and Governmental Subsidies of the District Heating Economy in the FRG. 4-42

4.1 INTRODUCTION

Canadians have appeared reluctant to adopt district heating as an acceptable form of heat distribution despite the fact that the technology, in widespread use for many years in a number of countries with similar climatic regimes, is considered to provide substantial economic and environmental benefits compared to individual heating systems. Although a number of specific district heating opportunities have been identified in Canada, examined, and (based on proven European DH technology) appeared to offer similar benefits, virtually none of these projects have gone forward to implementation.

Considering this apparent impasse, it is useful to review the history and development of district heating in other countries with a view to identifying those factors which may have acted as a catalyst to the development of district heating and determining the extent to which those factors exist, or could be created in this country. In addition, Canada's experience is also reviewed in an attempt to identify possible impediments to implementation.

Experience in the United States, the country in which district heating originated, is examined because in many important ways including lifestyle, individual values, institutional organizations, energy options, and climate (at least in its northern regions) it is very similar to Canada. In addition, experience in a number of European countries, where district heating has enjoyed its greatest acceptance, is also reviewed.

4.2 EXPERIENCE IN OTHER COUNTRIES

421 EXPERIENCE IN THE UNITED STATES

.1 General

The IDHA District Heating Handbook provides the following account of the development of district heating in the USA.

> "In 1877, Birdsill Holly, a noted hydraulic engineer and inventor, pioneered the first commercially successful district heating system. Using a boiler in his cellar as the central heat source, Holly developed a loop of steam distribution, radiation, condensation, and return for his own home. This was followed by increasingly distant extensions of the system to heat neighbors' homes up to 1,000 feet away. The distribution line was iron pipe, wrapped with asbestos, felt, and paper, buried about three feet deep in a wooden box filled with sawdust. His initial efforts were so successful that he was able to raise the necessary capital to found the Holly Steam Combination Company in Lockport, N.Y., which began service with 14 customers. By 1879 Holly's corporation had nearly three miles of line in service, and by 1880 the steam service was extended to include several factories. By the following year the industry had grown so fast that the first district steam equipment manufacturing corporation was formed.
>
> Within a decade, district heat using a steam transfer medium had expanded to ten cities in Pennsylvania and others as far away as DuBuque, Iowa, Denver, Colorado, and New York City.
>
> In 1879, the same year Thomas Edison was installing electric lines in New York City, the Steam Heating and Power Company of New York was founded. Soon thereafter a competing firm, the New York Steam Company was established. As many small electric utility companies evolved to meet the new and growing demand for electricity utilization, it became apparent that use of the exhaust steam from their power generation was an obvious opportunity to add to profits.

> As efficiencies of scale began to be added to electrical generation, the DH industry suffered. The advent of closed-cycle turbine generators lacking exhaust steam, and of larger, more efficient but less centrally located generating facilities limited the growth potential of the steam industry. Steam being a by-product of the generating process which could be sold very inexpensively, had been a second profit center for electric utilities. However,generation of steam separately from electricity greatly increased costs and utilities were forced to raise rates. In 1909, the year the National District Heating Association was founded, about 150 DH systems existed in the United States. Many operated marginally or at low profit. The cost of converting from exhaust steam to live steam had been a shock to the industry. From that low point, however, the management and profitability of DH systems improved dramatically through most of the first half of this century.
>
> Since World War II, district heating in the U.S. has remained virtually static, as low-cost and abundant fossil fuels and electricity have overshadowed many of the advantages of district heating. However, European nations during the same period had significant success with hot water-based district heating."[112]

It is clear from the foregoing that district heating has had a long and varied history in the U.S. Due to the country's size, diversity, and the general fragmentation of the district heating industry, comprehensive statistical data which could provide a reasonably accurate indication of the industry's scope is not available. Estimates have placed total installed DH capacity at 40 GW and energy heat production at about 432 PJ, less than one percent of total primary energy supply [114]. This heating load is reported to be approximately equally divided among institutional facilities such as hospitals, universities and military establishments, housing complexes and industry. The major fuel sources for the systems are oil and natural gas, and to a lesser extent, coal.

There are approximately 45 public utility DH systems, the largest being the 4 GW Consolidated Edison system in New York City and the smallest being the 35 MW system in Fairbanks, Alaska. All but three of these utilities use steam as the main heat transfer fluid and although some utilities are expanding their networks, primarily for process heating, most systems remain static and several have experienced reductions in sales levels.

There are numerous accounts of technical and financial problems associated with operating steam DH systems in the USA. Most systems operate with overall efficiencies of less than 60 per cent and consequently are hard pressed to earn a reasonable return on investment. Increases in the price of heat are generally resisted by subscribers and regulatory authorities and are also limited by competitive pressures. In addition, the principal line of business of several large public DH systems is the production and sale of electricity rather than heat. These utilities, with the bulk of their revenues and profit arising from electricity sales tend to devote most of their effort and interest to the electrical side of the business, to the detriment of the DH operation.

While it is recognized that the economics of many steam DH systems could be improved by conversion to medium temperature hot water DH systems based on European technology, the capital costs of conversion, not only for the distribution systems but also for the conversion or retrofitting of subscribers heating systems would be substantial. These costs, coupled with concerns over disruption to general city and business activity during the construction period, are considered major deterrents to the conversion process.

Compared to many European countries, the level of direct government intervention in energy matters is relatively modest. Greater reliance is placed on the operation of normal market forces to achieve a reasonable allocation of energy resources. The recent and planned deregulation of oil and natural gas prices are tangible evidence of this philosophy. Involvement in encouraging various energy technologies at the federal level is limited primarily to creating a favourable tax regime for energy technologies. However recent federal legislation such as the Public Utilities Regulatory Policy Act (PURPA) and the Power Plant and Industrial Fuel Use Act (FUA) has had an impact on the development of cogeneration and therefore on district heating.

Sections of PURPA were intended to encourage the development of cogeneration by requiring electric utilities to attach cogenerators to the grid, wheel cogenerated power and purchase cogenerated power at a ceiling price equal to the utilities' incremental cost of alternative electric energy. In addition the Act exempted qualifying cogenerators from certain regulations in the Public Utility Holding Company Act and Federal Power Act as well as state public utility regulation. It is estimated that these measures have contributed to the development of over 9000 MW of installed industrial cogeneration capacity [173]. However equity participation of more than 50 percent by an electric utility disqualifies a cogeneration project from the economic and regulatory incentives provided under PURPA. This provision is intended to prevent electric utilities from avoiding regulation, however it is considered by some to discourage the development of cogeneration facilities by utilities - entities that are likely among the best equipped financially and technically to own and operate these types of plant.

The FUA, in some circumstances, prohibits the use of oil or natural gas in new electric utility generating facilities, or industrial boilers, having a fuel input in excess of 100 million Btu per hour. Cogeneration facilities may be exempted if the economic benefits of cogeneration are unattainable without using oil or gas. While the FUA was intended to encourage the use of lower quality fuels and to conserve high grade fuels, it has in some instances made it difficult for potential cogenerators to comply with national ambient air-quality standards.

The federal government has also affected the level of interest in and development of district heating, through the Department of Housing and Urban Development (HUD). This Department provides grants to assist in the financing of pre-feasibility and detailed feasibility studies of district heating for a number of cities located throughout the United States. In addition, HUD through the Urban Development Action Grant (UDAG) scheme has acted as the grantor of last resort for up to 15 percent of the total investment in district heating projects.

While it is difficult to predict the future course of development of district heating, much will depend on the successful completion and operation of a number of new projects, some of which are based on European district heating technology. Several of these projects are briefly discussed in the following pages.

.2 Lawrence, Massachusetts [111]

Lawrence, Massachusetts is a textile manufacturing center located approximately 30 miles north of Boston. The city has had significant exposure to steam heating since the turn of the century with a number of textile mill buildings and processes dependent on steam supplied from central boiler plants fired initially by coal and later by oil and natural gas and distributed through a piping network.

In 1980 the Department of Energy (DOE) and the New England Innovation Group developed a comprehensive energy and economic development program for the city which identified several major energy conservation projects. A grant from HUD enabled the city to assist a private developer to assess the feasibility of a resource recovery/district heating system.

All necessary commitments and clearances for the first phase of the project were obtained early in 1982 and construction of the first phase of the system began in June, 1982. The capital cost was $90 million and was raised by the developer from private sources but with the backing of HUD and the cities of Haverhill and Lawrence.

The principle fuel for the district heating system is a refuse derived fuel having a heat content of approximately 12,800 kJ/kg. The fuel is produced at a new central resource recovery plant that was completed in March 1984 and is located in Haverhill, a city bordering Lawrence. The plant is designed to process approximately 1,200 t of municipal and commercial refuse per day. At the facility, the solid waste is dumped, inspected and then shredded with ferrous metals and non-combustible material removed.

The fuel produced at the resource recovery plant is delivered by trucks to a new heat plant in Lawrence which was completed in the summer of 1984 where it is burned to create steam.

Steam from the heat plant is supplied to the nearby Arlington Mills powerhouse to feed five turbine generators cogenerating electricity and steam.

The steam is used to supply existing customers in the Arlington Mills complex and in addition is also supplied to a nearby paper mill for process and heating requirements via a new 2.5 km long high-pressure steam line. This steam line has recently been connected to two public housing complexes to supply 324 dwelling units.

Electricity is sold to some of the existing customers within the Arlington Mills complex. Any surplus electricity produced from refuse derived fuel is sold to the New England Power Company at 85 per cent of its avoided cost.

The new heat plant using the refuse derived fuel produces substantial surplus steam. Future expansion plans include extension of the steam supply system to other industrial areas of the city and the development of a hot water district heating system for a residential area containing in excess of 2400 dwelling units.

.3 Trenton, New Jersey

Trenton, New Jersey, located about 80 km south of New York City is an old industrial city with a population of about 100,000. It is the state capital and houses the state legislature, state office buildings and a major state prison.

The Trenton district energy project was the first cogeneration/DH utility in North America to use hot water to distribute heat to a city community. Unlike many cogeneration systems which use steam turbines as the prime mover, the project uses diesel engines with heat recovery.

This project was initiated by the municipality in 1977, which with the assistance of a DOC study grant conducted a major $800,000 feasibility study of a steam based DH/cogeneration project for the downtown core. The project, as it finally evolved, had to overcome substantial technical and institutional barriers, however regulatory approvals, financing and contracts, were in place by the end of 1982. Construction began in March, 1983 and the system was commissioned in 1984 under the ownership and operation of the Trenton District Energy Company (TDEC), a privately owned partnership.

The DH system supplies thermal energy to approximately one half of the 25 customers who have agreed to buy heat from the system, most of which are either state or county departments or agencies. A few apartment buildings are included as well. Negotiations with prospective customers are taking place, among which, the City of Trenton has indicated an interest in connecting the City Hall and other municipal buildings to the system.

The total cost was under $25 million and the financing package included:

HUD-UDAG project loan by City of Trenton	$ 3,800,000
Tax-exempt industrial development bonds	10,000,000
Lease of powerplant equipment	9,700,000
Direct grant from DOE	370,000
Total	$23,870,000

The central plant is a cogeneration plant which will simultaneously produce 12 MW of electricity and 50 MW of thermal energy. The major components for electrical production are two 6 MW diesel generator sets. The engines will burn either natural gas or No. 2 fuel oil. Thermal energy production is provided by two 25 MW supplementary fired exhaust heat recovery boilers. Exhaust gas from the diesel generator sets is directed to a mixing chamber in one of the boilers where outside air is added to provide sufficient oxygen to support combustion. Supplemental fuels can be burned with the mixture of exhaust gas and air when needed to respond to hot water heating demands in excess of the amount of heat supplied by the hot exhaust. Natural gas is the principal fuel added, however, the system is designed also to use No. 6 fuel oil (high sulphur), with the potential to fire either fuel separately or in combination.

The hot water distribution system is 7.2 km long and provides water at 200, 160, and 120°C. About 80 per cent of the lines are placed underground, utilizing pre-insulated (foam glass and polyurethane foam) welded steel pipe using standardized components. The remainder of the distribution system is installed in locations within connected buildings and intermediate buildings such as parking garages. These pipes are insulated with mineral wool insulation. All pipes are supplied with a leak detection and alarm system which provides continuous monitoring.

The superheated water is converted, in mechanical rooms in the various buildings connected to the system, to a variety of thermal energy forms, including steam to provide both heating, cooling (absorption air conditioning systems), to sterilize hospital and laboratory equipment, and to operate laundry facilities.

While the project was designed and constructed in general accordance with current European technology, HTHW was used instead of MTHW as a compromise between the conflicting objectives of maximizing operating efficiency on the one hand, and minimizing the cost of retrofit work to the subscribers' systems on the other. It was decided to use a HTHW distribution heat transport fluid because most existing subscriber systems operated with a steam fluid and HTHW enables low pressure steam to be produced in the subscriber systems with relatively minor changes when connected to the DH system.

As indicated earlier the project encountered a number of difficulties. Originally conceived as a steam based system, it ultimately had to be developed as a HTHW system and significantly expanded to make if financially viable.

In order to make the project financially viable long-term heat supply contracts were sought. This objective was achieved with the State and a major medical center both of which signed 20 year contracts, but the TDEC was unable to negotiate an "all events" type contract with the local electric utility for the purchase of cogenerated electricity. To reduce the project's risks to levels which would be acceptable to the financial community TDEC also negotiated a lump sum turnkey construction contract with a 100% performance bond, obtained a 10 year fixed cost maintenance contract and conversion efficiency guarantees from the diesel supplier, obtained business interruption insurance and a state obligation to operate the project in the event of a major outage. TDEC also encountered difficulties over limitations on the maximum allowed capital cost for a project financed with tax-exempt bonds which were considered vital to the project's economics. This was finally resolved by leasing rather than purchasing the generating equipment.

The project also encountered difficulty in attempting to comply with the conflicting requirements of the FUA and the state's environmental requirements that was ultimately and inadvertantly resolved when the project switched from turbines to diesel engines, which are exempt from the FUA.

.4 St. Paul, Minnesota [70] [111]

The St. Paul district heating project had its origins in a study initiated by DOE and the Minnesota Energy Agency (MEA) to determine the feasibility of hot water district heating in U.S. cities. The Minneapolis - St. Paul area was selected as the study site because, among other things, it experiences a high number of heating degree days (4,450), had a large potential load, and offered access to a variety of different energy sources. The object of the study was to outline the general features of a new Twin Cities - wide hot water DH system, assumed to develop over a 20 year period.

Following encouraging study results and the recommendation that St. Paul be the subject for closer study the District Heating Development Company (DHDC) was incorporated in July 1979 as a non-profit company by the Mayor of the City of St. Paul, the Executive Director of the St. Paul Building Owners and Managers Association and the Director of the Minnesota Energy Agency (MEA). Additional feasibility studies were performed from mid-1979 through the end of 1980 to assess the preliminary economic feasibility of a hot water DH system serving the commercial core area of St. Paul. The final economic feasibility study was completed in September 1982, financing was arranged in December, 1982 and construction began in March, 1983.

Services to DHDC's first customers began in September, 1983 and over 70 buildings will be connected to the system by 1985.

The market area consists of over 300 buildings. At the time of the study, the existing total heat load for the area was estimated at 245 MW and city development plans for 1980-85 were expected to create another 40 MW of load, for a total of 285 MW. Government buildings and hospitals represented one third of the building load and it was necessary to obtain assurances that these facilities would subscribe to district heating because they comprised such a large portion of the potential market.

The initial project cost was $45.8 million financed as follows:

Tax-exempt revenue bonds (30 year term, 9.66% effective rate)	$30,500,000
HUD-UDAG loan ($7.5M-HUD, $2.5M-City) (30 year term, 5% rate)	9,800,000
City of St. Paul equity loan (no interest, repaid as revenues available)	5,500,000
Total	$45,800,000

In addition subscriber conversion costs were about $22,000,000.

The principal heat source for the system is a 180 MW retrofitted coal-fired plant, originally owned by the Northern States Power Company (NSP) and sold to the St. Paul Steam Company, an affiliate of DHDC, along with the existing steam DH system. Back-up is provided by 30 MW of natural gas/oil-fired boiler capacity located at another power plant. As the load grows it is contemplated that turbine units at NSP's High Bridge Power Plant will be converted to cogeneration, possibly in 1986, to improve the efficiency of electricity production and to increase heat source capacity for the DH system.

The DH system delivers MTHW (90°-120°C) through 15 km of twin underground transmission, distribution and service piping ranging from 50 to 700 mm in diameter. The system uses a polyurethane-insulated steel pipe encased in a polyethylene jacket for the distribution system. The preliminary design outlined a hot water piping system to serve all the existing and future heat demands in the initial area, up to a total capacity of 280 MW.

One of the main concerns in supplying the existing building heating systems from a MTHW system was the degree of retrofit work required for various buildings. There was considerable diversity of building heating systems in the St. Paul central business district due to the wide range of building sizes and ages which ranged from new to 90 years old. Therefore the cost of building retrofit was one of the key economic and marketing issues for the project.

In this respect a somewhat different approach from the Trenton project was taken. The overriding philosophy of the conversion design was to optimize the life-cycle cost rather than to minimize the first cost of connection to the hot water system. The minimum first cost strategy would require a year round hot water supply temperature in the range of 150-180°C. Such a HTHW system could be used to heat buildings with existing steam distribution systems as was used for the Trenton project. This strategy had the lowest initial conversion cost but it would be less efficient, more difficult to control, and more costly to maintain than the MTHW system.

It was decided that the hot water supply temperature would be limited to 120°C to reduce the construction and operating cost of the DH system.

As noted earlier, conversion and, in many cases, upgrading of subscriber systems cost about $22 million. This capital cost created a serious hurdle for potential subscribers to overcome, particularly non-profit cultural organizations, social service agencies, and hospitals. These large institutional facilities were essential base loads for the economic vI$_t$Ö?lity of the district heating system, however these subscribers were least able to cope with the capital requirements of connecting to the system. This problem was overcome through a variety of conversion loans, grants and private and corporate donations.

In order to reduce the project's financial risk and improve the marketability of DHDC's proposed revenue bond issue, the Company's financial advisers recommended obtaining firm lump sum bids on the project to minimize construction risk and firm long-term "all events" heat supply contracts with large credit worthy customers. DHDC was successful in obtaining firm contracts for project construction but faced considerable resistance from potential customers to a proposed 30 year heat supply agreement with limited rights of termination. DHDC ultimately had to revise the customer contract to provide greater protection to potential subscribers in order to obtain the long-term commitments they were seeking.

.5 Conclusions

It would appear that district heating in the United States is in a transitional phase as the industry attempts to switch from a steam based technology to hot water. Interestingly, the more significant recent developments in the industry seem to be occurring in areas which had already been exposed to some form of district heating such as Lawrence, St. Paul and Trenton rather than in communities where there has been no prior district heating experience.

While the private sector has played a major role in these initiatives, municipal governments appear to have been the principal motivating source and have made significant contributions to the success of these projects, ranging from taking an ownership position in the case of Willmar MN, to providing assistance in arranging study and project financing, and providing indirect support as major customers of these systems.

The federal government has also played a significant role in funding initial feasibility studies and, as can be seen from the financing arrangements previously outlined, provided not only direct project financing through HUD-HDAG grants but also indirect financial assistance via federal and state tax exempt revenue and industrial development bonds that gave these projects access to capital at rates substantially below then current financial market requirements. Federal and state government facilities have also represented important base loads that enhanced the economic and financial viability of the projects particularly during the early development stages. Recent federal legislation such as PURPA and the FUA appears to have had mixed results in its impact on the prospects for district heating, creating incentives in some instances, obstacles in others and in some cases, potential conflicts with other legislation.

422 EXPERIENCE IN EUROPE

.1 General

The Dresden system in Germany, commissioned in 1900, is considered the first district heating system in Europe. In addition, several other district heating systems were started in Europe in the

1920's including systems in Hamburg, Kiel, Leipzig and Copenhagen. Only in recent decades, however, has district heating developed rapidly in some European countries. Market penetration is very high in Denmark, Finland and Sweden. In Denmark district heating serves more than 40 per cent of all space heating requirements and in Sweden and Finland, approximately one third of all space heating is provided by district heating. Table 4-1 shows district heating's market share in a number of European countries.

In absolute terms, district heating has been made its greatest impact in Germany. Figure 4-1 illustrates the expansion of district heating in selected European countries since 1960.

A closer examination of the history, development and ownership of district heating in Denmark, Germany, the Netherlands, and Sweden follows. These countries were selected to illustrate a range of development forms, climates and competing energy alternatives and the impact of these factors on the level of market acceptance of district heating.

.2 Denmark

District heating systems currently serve more than 40 per cent of Denmark's residential and commercial space heating requirements. More than 30 per cent of single-family houses (about 400,000 units) and more than 50 per cent of flats and apartments are supplied with district heat. Though the term "district heating" generally applies to public supply systems, it is often difficult to make a sharp distinction between a system accessible to any consumer in the area of supply and a system providing a centralized heat supply to a group of buildings (block centrals). In practice, the two kinds of supply systems do not differ in respect to size or technical form.

TABLE 4-1

District Heating Market Share for Selected European Countries

Country	Percent Share of Heating Market
Austria	10
Switzerland	5
Germany	10
Denmark	40
France	10
Netherlands	2
Sweden	30
Finland	30

Sources: District Heating and Combined Heat and Power Systems, OECD 1983 and Proceedings of the IDHA 1984.

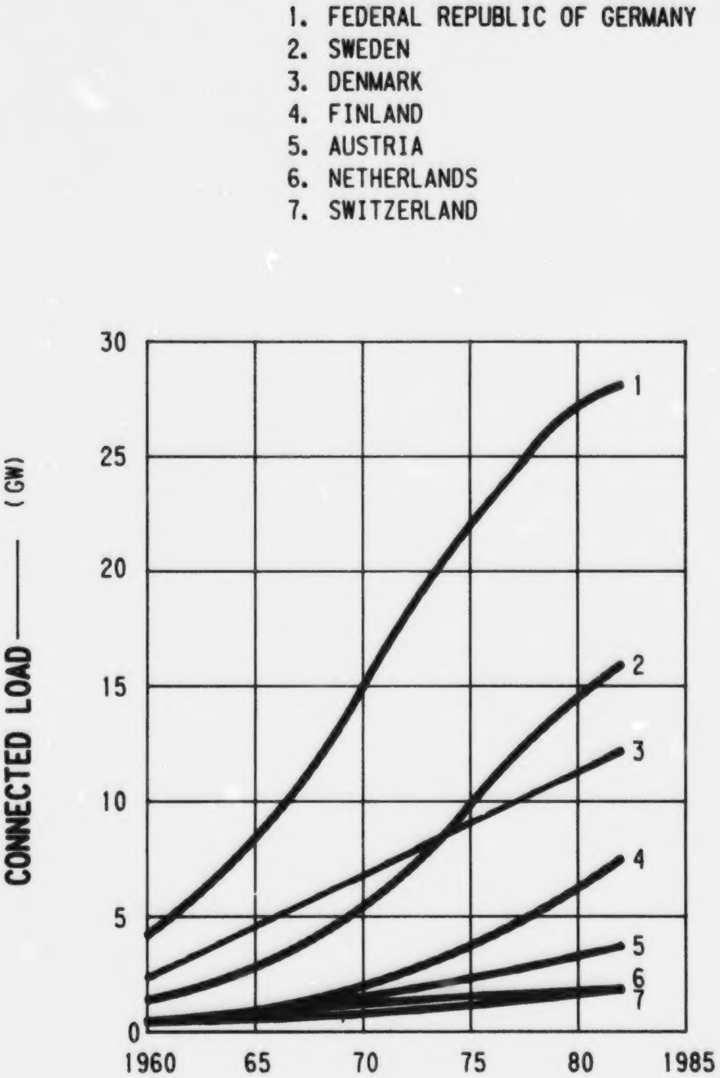


FIGURE 4-1
DEVELOPMENT OF CONNECTED HEAT LOAD

SOURCE: IDHA (1984) PROCEEDINGS - EXPERIENCES WITH FORCED EXTENSION OF THE DISTRICT HEATING SUPPLY IN THE FEDERAL REPUBLIC OF GERMANY -H.P. WINKENS

The current DH industry in Denmark consists of approximately 350 collective systems. Fifty of these systems (representing about 65 per cent of the total DH production) are municipally owned. The remaining systems are, to a great extent, organized as consumer cooperatives. Seventeen of the DH systems are currently served by combined heat and power (cogeneration) stations. These systems, however, account for 45 per cent of the total heat production. About 50 systems receive waste heat from refuse incinerators or from industrial processes (five per cent and one per cent respectively of the total heat production) and some large heat pumps using sewage or waste heat have been installed on an experimental basis over the past few years. Most of the systems, with the exception of the Copenhagen steam system, are low and medium temperature hot water systems with input temperatures ranging from 70°C in the summer to 120°C in winter and with return temperatures ranging from 45°C to 55°C.

District heating began in the twenties in larger towns, generally on the initiative of a municipally owned electric utility which saw it as a way of marketing the heat in the cooling water of its diesel generators. District heating developed by cooperatives however, did not involve electricity production.

The cooperative model of organizing for collective needs has a long tradition in Denmark, dating back to the period during the nineteenth century when Denmark abandoned subsistence farming for an agricultural market economy. The model of agricultural cooperatives for production, processing and marketing of goods was adopted later for the service industries, among them district heating.

Following World War II, district heating began to enjoy increased acceptance. It was believed that consumers connected to district heating systems had suffered less from post-war fuel scarcities and district heating was also considered to be energy efficient. The major growth in district heating occurred somewhat later, however, in the period of 1958 - 1966, and largely in towns without any cogeneration potential. It was often initiated by homeowner associations or other consumer groups based entirely upon the principle of voluntary connection and developed with very little intervention or assistance from national administrative bodies.

The most important criterion for these new district heating projects was that they be self-supporting. The reduction in fuel costs had to be large enough relative to individual heating systems to offset the fixed costs of the DH system. This made it necessary to find technically and administratively simple systems. In many cases this goal was achieved and resulted in operational reliability and economy. However, it now appears that a number of these district heating systems were not designed to last a "normal" lifetime. This is reflected in the current need for renovation to district heating pipes, especially those constructed of concrete. Repairs occur 20 times more frequently on the 8,400 km of concrete pipe than on the 5,600 km of the factory insulated steel pipe systems which constitute the modern heat distribution technology. Water losses in concrete pipes are reported to exceed 1.4 million m^3/year and heat losses in Danish DH systems could be reduced from 25 to 15 per cent, if concrete pipes were replaced by steel pipe systems. A renovation program for concrete pipes extending through the next decade has been developed with a total cost estimated to be 3 - 5 billion Danish crowns ($1 = DKK 8.20). Modern main piping systems use steel pipes in concrete ducts for large diameter (over 600 mm) systems while smaller diameter systems are prefabricated, preinsulated steel pipe-in-pipe systems.

Although the development of district heating in Denmark took place without central government intervention or financing arrangements, district heating development has been regulated by the "Letter of January 15, 1962, to all county governors from the Ministry of Interior" and the "Standard statutes of the Ministry of Interior of July 16, 1963". The letter of 1962 outlines rules and regulations for county councils when a DH system is established, in order to ensure its financial viability, especially if organized as a municipal undertaking or as a non-profit, cooperative with municipal loan guarantees. For example, not more than 80 per cent of the invested capital may be obtained by debt financing. The rest must be met by equity investments by the members of the cooperative. The repayment period should not exceed 20 years, during which time the owners of the connected houses must remain members of the cooperative. Cooperatives must not carry forward a deficit from one financial year to another and the cooperative bylaws must be in accordance with the directive issued by the Ministry which includes the right of public access to the district heating network. Finally, the project must be submitted to the Ministry for technical and economic examination. The "Standard statutes" for district heating undertakings ensures that reasonable statutes are used when the community is financially involved.

As was previously noted the original principle of DH system connection was voluntary participation. The Ministry of Interior had originally opposed proposals making connection to a district heating system compulsory when releasing land for development. However, deferring to rational principles for development planning and also to environmental considerations, the Ministry reversed itself in 1969. Since then it has been possible to force a land purchaser to connect a district heating system on "general connection conditions" (the same conditions as for voluntary connection).

Since 1969, district heating societies have been exempt from corporation taxes to the same extent as electric and gas utilities. Conditions for tax exemption are public access to the district heating system within the supply area and that profits be reinvested in the DH system.

The national government presented the first coordinated plan for the development of both the supply and demand side of the Danish energy system in the "Danish Energy Policy 1976". For the first time, government subsidies were provided to the district heating sector to promote oil substitution. Grants of 65 million Danish crowns were provided in 1977-78 as a 25 per cent investment subsidy on investments in transmission lines to connect cogeneration units to load centers. In 1979-80, 260 million Danish crowns were provided for the same purpose.

In 1979, the Danish Parliament passed the Heat Supply Act. According to this Act, the Minister of Energy, the county councils, and the municipal councils are responsible for the planning of heat supply systems. No heating scheme of importance can be implemented without the approval of these authorities. The Minister of Energy is responsible for the national heat planning and coordinates regional and local heat supply plans developed by the counties and the municipalities in cooperation with utilities and other interested parties. The heating plans must describe the organizational framework for implementation and operation, financing, and pricing policy and demonstrate that the schemes to be implemented are viable and in compliance with the objectives of the overall energy policy.

The Heat Supply Act also provides for the allocation of heat supply systems (district heat or natural gas distribution systems) on a local and regional level. The dividing lines between supply systems were developed by assigning each part of the country to one of four main supply schemes. In three of the four supply schemes, centralized supply systems are planned, based upon natural gas, district heating or both. The fourth scheme is for areas not considered suitable for natural gas or district heat. As expected, development of dividing lines between supply systems has created problems when the same geographical areas are of interest to both natural gas and district heating suppliers. The government is the financer and owner of the natural gas system at all levels. A number of district heating plants have contracts with natural gas companies for delivery of natural gas at prices that are competitive with fuel oil and further use of natural gas in cogeneration stations is expected.

The Heat Supply Act has also affected existing district heating systems with respect to generally accepted principles of conditions of service. The municipal council can now decree that a collective heat supply undertaking should carry out a specifically approved project within an assigned time period. If it will not (or cannot) comply, it can demand municipal take-over. The law also makes it possible for the municipal council to regulate connection obligations for existing buildings. Property owners can be charged with contributions to a collective heat supply system if connection is possible, even if no connection has taken place. Finally, the municipal council can prohibit the use of specified heating systems for new buildings within a specified geographical area. Several municipalities have used this power to prevent direct electric heating.

According to the Heat Supply Act, heat supply prices are based upon actual costs and all prices, together with the basis for their determination, should be reported to the Gas and Heat Price Committee for approval. The Gas and Heat Price Committee is made up of six representatives from the energy supply interests (electricity, gas, district heating), five consumer representives and three technical experts. This committee has already had an influence on supply conditions for DH systems. For example, it has stated that special fees to be paid by DH consumers investing in (and using) other energy systems will "come into conflict with the general energy policy". The committee has also found that limitations on the consumer's right of termination from the district heating system for 20 years (which is a common condition of service in the consumer's contract) were unreasonable. It came to the same conclusion with respect to another common condition of service in which a consumer must agree to take all heating energy needs from the district heating company.

It is clear that the Heat Supply Act could transfer some of the financial and operating risk that previously had been carried by the subscriber to the operator of the district heating system. However, the implementation of its rules lies very much in the hands of the local municipal council.

The high level of penetration of district heating in Denmark is likely the result of a number of factors including the country's history with the cooperative movement and community involvement, significant municipal involvement in the energy sector and the relative absence of low cost energy alternatives, most notably natural gas. The recent availability of natural gas may have a significant impact on the future prospects of district heating. One of the principal purposes of the Heat Supply Act is to ensure the rational development of these two competing energy forms in the future.

.3 Sweden

While block centrals arranged to serve a specified consumer or group of consumers have an old tradition in Sweden, heat distribution systems offering heat to all consumers in parts of a municipal area, were not introduced in Sweden until about 1950. A proposal for such a district heating system was presented as early as 1909 (the Ostermalm district of Stockholm) and system designs including cogeneration stations were presented in the forties (e.g. for Norrkoeping and Stockholm). However, it was not until 1948, at a conference in Gothenburg on the topic of heat and power production systems, that municipal interest for district heating was awakened. Shortly afterward, the Swedish District Heating Association was founded and the first DH systems were established in Karlstad and Malmoe.

The main theme throughout the Gothenburg conference was the recognition that Swedish hydroelectric resources would soon be fully developed and that other electricity production alternatives had to be found to meet additional loads. Cogeneration of heat and power was an energy efficient alternative with appeal to municipalities since it might lead to an increase in the proportion of electricity supplied by the municipalities.

The capital intensive characteristics of the cogeneration DH system apparently did not represent a major deterrent to implementation and financing of the first systems does not seem to have caused significant problems. During the fifties the concept was introduced in ten Swedish cities, including Vaesteraas, Norrkeoping and Stockholm. Although there was concern that municipal power production weakened the monopoly in the electricity business, relations with traditional power producers (such as the State Power Board) were generally cooperative. In 1950 a large portion of Sweden's electricity was produced from hydroelectric sources. Forty percent of hydroelectric output was controlled by the State Power Board. The remaining 60 per cent was divided between private and municipally owned companies.

Towards the end of the fifties, the availability of capital to municipalities diminished, oil prices declined and the resistance of the electricity producers towards district heating increased. At the same time, it was evident that the DH concept had more advantages than just those associated with municipal power production. Environmental advantages over individual oil-fired heating systems, decreasing operating costs for owners of multi-unit dwellings, and favourable economic experience with the first DH systems, were stated in support of continued expansion of district heating.

An important step in the promotion of district heating development was the agreement on standard tariffs for new DH systems in 1958. The main principle underlying this tariff was that district heating should never be more expensive to the consumer than an alternative individual oil-fired system. The connection fee was given special attention. Government guaranteed low-interest mortgages for new houses included a specified amount for the heating system and it was considered that connection to a DH system should not alter the basis of the government loan. Therefore, the tariff was drawn up so that the sum of the connection fee and other costs for the connection (central piping system, control and metering equipment) would be covered, in principle, by the heating system loan increment.

Thus, with implicit government consent, part of the investment for establishing and expanding district heating systems in Sweden was financed through the low-interest mortgages (4 - 6 per cent below normal interest rates) given by the government for new housing. This support is still in existence.

In the 1960's, nineteen new district heating systems were established, the expansion being furthered by the government's concentrated housing construction program aimed at eliminating the shortage that had been created with the urbanization process of the fifties and sixties. The new district heating systems were all oil-fired as were the earlier systems, but were, with few exceptions, heating systems only. The power companies had found measures to limit the growth of municipal power production.

One approach was to seek cooperative agreements with the municipality in which the power company assisted in the financing of the cogeneration station and assumed operating responsibility for the plant. Some cogeneration plants were erected on this basis but in many cases the municipal utilities found the arrangement unsatisfactory because the parties had differing opinions on the price for cogenerated electricity and consequently the plant was seldom operated. The power company also set high stand-by charges for firm capacity to the municipality or indicated a willingness to renegotiate more favourable high voltage power tariffs to the municipal utility when it was evident that district heating was being seriously considered.

The strategy of the power companies (mainly represented by the State Power Board) was effective and is understandable considering the tremendous nuclear power program anticipated at that time. When the nuclear power program began to come under strong public debate (first connected with the question of "thermal pollution") in the early seventies, the district heating interests tried to point out to the government the enormous undeveloped potential for energy efficient power production that was hidden in the municipal "heat-falls". A study to prove the profitability of cogeneration plants (jointly performed by the power industry and the district heating interests) ended up in disagreement. However, in spite of strong marketing efforts to expand the use of electrical heating, district heating continued to increase its market and from 1970 until the oil crisis in 1973, nineteen new DH systems were established. The oil crisis of 1973 effectively killed all proposals for oil-fired cogeneration plants.

The Swedish government launched the first Swedish energy policy program in 1975. Since that time promotion of district heating has been a vital part of the national energy policy. As a result, almost seventy new district heating systems have been put into operation since the first oil crisis. During the seventies, the heat load connected to DH systems tripled. About 1.8 million dwellings, approximately 50 per cent of the total (0.8 million single-family houses) are now connected to municipal DH systems. The total connected heat load amounts to about 16,000 MW; and, the annual heat delivery is about 100 PJ. The five biggest district heating cities

(Stockholm, Gothenburg, Malmoe, Vaasteraes, Uppsala) represent 40 per cent of these figures.

While Sweden continues to experience surplus electrical capacity and low cost electricity due to extensive hydroelectric and nuclear resources, and this situation is likely to continue until such time as the nuclear facilities are phased out, the roles of electricity and district heating have been rationalized somewhat. Electricity is now seen as suitable for low-density areas, including single-family dwellings while district heating is preferred for high-density areas.

With district heating part of the national energy strategy, the national government has tried to promote its development by various forms of legal and financial support. Initially the municipal DH utility had no legal means of forcing a householder to connect to the system. Every connection of an existing building was the result of a voluntary agreement. For new areas, however, especially when the municipality originally owned the land, compulsory connection to district heating systems could be enforced. In many Swedish cities, the principle of leaving the type of heating system to the discretion of the homeowners had resulted in a situation where many different heating systems could be found on the same block. This was considered unsatisfactory and a state committee proposed in 1970 that all municipalities should draw up plans for the heating of densely populated areas. In 1972, the Swedish Association of Municipalities demanded that the government give municipalities the legal right to "solve heating questions in a more rational way". After an investigation by a state committee, Parliament issued an Act on Public District Heating Systems in 1976.

According to this Act, the district heating operator was given the power to forcibly connect all potential customers within its distribution area, including those with existing and perhaps rather new individual heating systems. Such compulsory connection, however, requires that the DH system be declared a "public system" for the area by a national authority. The operator of the public system (preference given to municipal utilities) is obliged to allow the connection of all buildings within the system area and to supply the buildings with all the energy necessary for their heating. The operator of a public system is also subject to the regulatory provisions, including tariff setting, laid down in the Act.

While the Act gave the municipalities the legal rights they had been seeking, the law has never been enforced. No public heating system presently operates under the provisions of the Act. The reason for this may have been concern about public reaction to implementing district heating through a compulsory connection policy. However, a more likely explanation is that the law was made practically unnecessary in 1977 by an amendment to the General Act on Electricity (1902). This amendment stated that a distributor of electricity is not obliged to supply electricity for heating purposes to a house situated in an area in which district heating will be available in a municipal heating plan. In recent years when the main competitor to district heating has been electricity, this amendment has been found effective by several municipal energy utilities who distribute both electricity and heat.

Another piece of government legislation which served to promote district heating was the Act on Municipal Energy Planning (1977). This Act stated that a municipality in its planning should promote energy conservation and ensure a safe and sufficient energy supply to the community. It also stated that each municipality should have a current plan to reduce oil consumption in the community. This plan should be approved by the municipal government. Thus, municipal heating plans, where the borders between various energy systems are outlined, have been given legal status and have been used to promote DH system development.

On the financial side, the last ten years of energy policy programs have created a number of government subsidies. Since 1974, connection to district heating has been an activity which has been entitled to grants and/or favourable loans, however, since 1977 the rules for these subsidies have changed seven times. The total financial support given to promote connection to district heating is therefore hard to estimate; but, for example, in the period of July 1, 1977, to December 31, 1983, the National Housing Board received applications for district heating connections for existing houses at an approved cost of about SEK 1.5 billion ($1 - SEK 6.5). The main part of this sum (SEK 1.35 billion) was for connection of multiple-dwelling units.

Under government policy, in addition to grants and loans for district heating connections, grants and loans for extra house insulation, installation of triple-glazed windows and even a heat pump installation are also available to the same house owner. This sometimes results in more money being spent on energy conservation than is cost-effective.

In the mid-seventies, district heating companies reported severe difficulties obtaining long-term financing for expansion. It was also argued that it was difficult to include district heating investments in the limited credits that government allotted to the municipalities. From 1977, a new financing system was introduced with government approval. Two financial institutions were permitted to issue bonds within limits authorized by the National Bank of Sweden. These bonds were sold to the General Pension Foundation, banks, insurance companies and even individuals. Funds received were loaned to municipalities and to district heating companies. These district heating loans were provided over and above the ordinary municipal credit limits set by the government and were fixed yearly installment loans with a term of 23 years with interest rate adjustments (at prime) every fifth year.

In 1983, in order to further the development of district heating systems, the government established a 10 per cent investment grant (SEK 300 million) for heat distribution systems ordered that year. District heating utilities could also take advantage of an investment grant of SEK 600/kW (maximum 25 per cent of the total investment sum) that was given for peat-fired production units ordered in 1983. The government reserved SEK 370 million for this purpose.

For 1984, the district heating utilities are entitled to a connection grant of SEK 135/kW of new connected heat load (measured at the production plant). For equipment ordered in 1984 using or distributing industrial waste heat, a 10 per cent investment grant is given. The 25 per cent investment grant given to peat fuelled production units in 1983 was changed, in 1984, to a 15 per cent investment grant for all solid fuel based production units.

If the district heating utility converts from oil to coal, it may also take advantage of a 75 per cent investment grant for pollution equipment.

A district heating utility participating in the technical development program by building prototypes or demonstration plants may receive investment grants of up to 50 per cent of the investment cost, plus loans (without security demands) of up to 75 per cent of the investment sum. The total of investment grants and loan cannot exceed 100 per cent.

A government delegation for energy purchases was created in 1982. It handles some of the investment grants and loans mentioned above. The delegation also has the responsibility for giving loans for investments in solid fuelled production units (in 1983 SEK 700 million).

The oil reduction program of the Swedish district heating utilities has drastically reduced the oil dependence of the systems in just a few years. In 1978 the oil dependency was 90%. In 1983 it was reduced to 52 per cent as shown in the following table.

TABLE 4-2

District Heating Fuels - 1983

Fuel Type	Per cent	
Fuel Oil	52	
Coal	16	
Electricity	12	
Refuse	7	
Industrial Waste Heat	4	
Wood Chips	4	
Blast Furnace Gas	2	
Heat Pumps	2	
Peat	0	(0.5%)
Others	1	
Total	100	

Natural gas has only recently become available to parts of Southern Sweden from Danish sources. It is not clear how the competitive position of district heating may be affected by the increased availability and possible use of natural gas as a fuel for district heating or for individual systems.

.4 The Netherlands

Except for two projects in Rotterdam and Utrecht (in existence 25 and 40 years respectively) district heating had a hesitant start in the Netherlands. The rather mild climate (average January temperature 2.5°C in Rotterdam), the ground conditions (high ground water levels and continuous settling), heating traditions (the Dutch used to heat just one or some of the rooms in the flat/house), and, after 1960, abundant amounts of indigenous gas resources, are all negative factors weighing against the development of district heating in the Netherlands. Even in what one might assume to be a favourable development situation such as Rotterdam after World War II, heavy government subsidies were necessary to promote district heating. In this case, the Dutch government guaranteed to cover two-thirds of the operating losses for 25 years. If possible, repayment would be made at the end of the contract period by the Municipal Energy Works in Rotterdam.

Major gas discoveries in Groningen in 1959 had a substantial effect on the energy picture in the Netherlands. An extensive network of gas pipelines was built and coal and oil virtually disappeared from the public heating sector. Gas was cheap and nuclear power was expected to penetrate the market within a short time. Government policy was to sell the gas as quickly as possible. Following the first oil crisis, however, it became evident that there might be strategic advantages to district heating. With district heating, one could utilize cogenerated heat, recover heat from refuse incineration, and waste heat from industry for example and then export natural gas in order to improve government finances. A study group appointed by the Minister of Finance in 1975, delivered an interim report in 1977 and a final report in 1980. The report was intended serve as a manual for provincial and municipal authorities to reach well-founded decisions concerning the possible use of district heating in their supply area.

Based upon these reports and the favourable political attitude toward district heating during the period of 1976 to 1981, 20 district heating projects were started in the Netherlands. Two small projects were started without financial support from the central Dutch government, one directly beside a power station and the other on Vlieland, an island, with the heat provided from an existing diesel power station. Three projects already in the construction phase have been stopped. In Leeuwarden, the combination of a delay in housing construction (more than double the time previously expected) and cost escalation of the waste incineration plant that was supposed to deliver the heat made the district heating project uneconomical. The second project in Spijkenisse ran into trouble with its heating supply (originally thought to be an Esso refinery). The third, in Dordrecht, faced the same building program difficulties as in Leeuwarden but the construction of the heat sources (waste incineration plant and coal-fired power station) was also scrapped in the planning phase.

The remaining district heating projects in the Netherlands, when completed, will supply heat to the equivalent of approximately 275,000 dwelling units (of which 110,000 are actually connected at present). About 60 per cent of this heat will be for dwelling units and the rest for commercial and public buildings. Four of the projects are for heating only, based upon municipal waste as the energy source. Most distribution systems are constructed with polyurethane foam insulated steel pipe with a polyethylene jacket.

District heating projects have, until recently, been given financial support from the central Dutch government via the Dutch Energy Development Company NEOM, which was founded in 1976 in order to promote energy conservation, efficient energy use and diversified energy supply. NEOM has stimulated the development of district heating both with subsidies and loans (totalling Dfl. 400 million, divided 50/50, \$1 = Dfl. 2.60). Initially, subsidies were provided to alleviate losses resulting from the capital expenditures. More recently, subsidies have been based upon how much gas the project is intended to save during the project life (usually 25 years). The subsidy amounts to 0.010 - 0.012 Dfl/m^3 of gas saved. The loans from NEOM have covered 15 - 20 per cent of the total capital expenditure for a district heating project.

In determining the level of government subsidies and loans to DH systems, it was thought politically unwise to provide those connected to a subsidized energy distribution system with cheaper energy than was possible for residents connected to unsubsidized energy systems. Therefore, the government has set a pricing policy for DH systems that the consumer pay, in total costs, the same in the district heating situation as he would if he had a heating system connected to the gas grid and in a similar manner i.e. a relatively low fixed charge and high energy charges. The consumer price thus consists mainly of a consumption dependent charge when the main part (about 75 per cent) of the costs of the district heating company based on cogeneration are fixed and not affected by the consumption level. A substantial reduction in the heat consumption, therefore, can have serious financial consequences for the system operator.

The pricing policy for district heating, although understandable from the central government's point of view, has very few economic incentives for the normal consumer to connect to a district heating scheme. If the DH system expands in a gas distribution area, it will decrease the market for the gas companies at a time when these are already hit by the effects of energy conservation. Therefore, almost all of the surviving district heating projects are to be found in new towns or districts. This substantially reduces the pipe-laying costs and makes it unnecessary to install a gas grid. Connection to the DH system in such new districts is compulsory, and this requirement is considered acceptable because of the previously mentioned pricing policy. There is, however, a difficulty which stems from the workings of the social housing policy in the Netherlands. The majority of the houses are financed by the government according to specific regulations which include a specified amount for the heating system. However, this amount does not permit the use of a capital intensive system like district heating, which has an investment cost per housing unit that may be twice that for conventional gas heating.

It is evident that the price of natural gas for residential and commercial customers is particularly important for the development of district heating in the Netherlands, and the price of natural gas has traditionally been set below the price of heating oil. It is now about 20 per cent lower than oil. The government has the intention of raising the relative price of gas over the next few years to a much higher level in order to free up additional gas for export. Income from the 40 billion m^3 gas that was exported in 1983 represented 18 per cent of total government income that year.

When judging the potential market for DH systems in the Netherlands, consideration must be given to the levels of insulation and energy use in the dwellings. Subsidies favouring energy conservation have been reduced considerably (except for a number of demonstration projects involving low-energy houses with extra insulation). Nevertheless, there is a clear trend towards more insulation and less energy use. In general, the present situation in the Netherlands does not bode well for district heating and some of the remaining DH projects may have difficulty in being completed.

.5 Germany

As of December 31, 1983, there were 117 district heating companies operating 496 district heating networks, excluding major block centrals, in the Federal Republic of Germany (FRG). More than 30 per cent of the systems were supplied from cogeneration stations. The connected heat load was about 31,000 MW, and the total amount of heat delivered in 1983 was more than 175,000 TJ. About 70 per cent of the load and 65 per cent of the energy came from cogeneration stations. The primary fuels used in the district heating systems are indicated in Table 4-2.

TABLE 4-3

Primary Fuels Used in District Heating

Type of Production Plant	Coal	Gas	Oil
	%	%	%
Cogeneration stations	43	38	19
Heat only plants	22	36	42
Total	36	37	27

The concept of district heating was introduced in Germany at the end of the 19th century, based mainly on extracting steam from power plants to heat public buildings (the town hall of Hamburg, a hospital in Munich, the Institute of Technology in Berlin, public buildings and private houses in Dresden). However, real development began after World War I when the electric utilities in several cities offered steam heating to extended municipal networks serving both public buildings as well as private consumers. It is estimated that in 1939 there were about 33 district heating systems in the present FRG area, practically all operating with steam as the heating medium and most based on cogeneration.

After World War II district heating expanded; but still, it was to a great extent based upon steam heat extracted from municipal electricity plants; only occasionally were real back pressure plants or heat only plants used.

Oil heating was introduced about 1950 and gained a considerable share of the heating market from coal. In response, the coal mining industry sought a method of marketing coal in a form that could offer the consumer the same costs and comfort as private oil heating and considered district heating the solution. The coal industry founded the Ruhr Coal Company for District Heating Networks as a private company to promote DH networks fueled only by indigenous coal. Similarily, Preussag and the Eschweiler Bergwerks-Werein were founded to promote district heating in order to ensure the long-term demand for coal. District heating companies founded as a result of this marketing initiative were, however, mostly municipally owned. In a survey in 1972, it was found that more than 80 per cent of the connected heat load was served by municipally owned companies.

If the first step in the development of district heating in the FRG was the extraction of (steam) heat from city power plants and was thus connected with the electric supply industry in Germany, the activities of the coal mining industry in the fifties would mark the second stage of district heating development in the FRG. The amount of heat delivered to the DH networks increased by seven fold between 1950 and 1960.

The legal basis for energy planning at the national level is the Act for the Promotion of Energy Industries (EnWG) of 1935 and its wide variety of regulations. The EnWG regulates the relationship of the energy supply companies among themselves and with consumers. Demarcation agreements divide the supply districts between supply companies. In order to ensure a cost efficient and reliable energy supply, these companies are subject to government control by the Federal and Laender (provincial) authorities. Government supervision also includes notification and approval requirements for construction, expansion, renewal and abandonment of generating and distribution plants. It should, however, be noted that in contrast to electricity and gas, district heating is not defined as energy within the context of the EnWG. Consequently, regulations such as those dealing with compulsory connection and supply, easements and expropriation, and supply area demarcation do not apply to district heating, unless the system is regarded as a secondary activity to power production.

The involvement of the federal government during the first two development stages of district heating is not clear. It appears that the federal government considered it unnecessary to provide financial support or to use compulsory measures to stimulate or enforce connection to DH systems above and beyond those powers already existing in municipal or civil law. It was possible for municipalities to forbid the use of certain fuels in certain areas if it endangered human health and to force connection to a DH system when selling land for development. These powers were used occasionally. In the main, however, up until the first oil crisis there were very few legal or financial incentives which would explain the rapid development of district heating that took place in the FRG. For the most part, district heating developed in areas where alternative energy systems were available and were controlled mainly by municipalities.

Beginning in 1973, the federal government responded to rising oil prices and concerns over security of supply by formulating policies emphasizing oil substitution, mainly by transition to nuclear energy and energy conservation. The energy program of 1973 has been revised several times, the third revision being made in 1981. In the energy program local authorities are required to develop local supply concepts for the development of major energy systems which will allow reasonable development of electricity, gas, and district heating based on cogeneration and heat generated from industrial waste. Supply companies and public authorities are now working together in designing energy supply concepts for many cities, local communities and regions.

The energy program has given a very prominent position to district heating. The background for this position is probably to be found in a major study on the feasibility of district heating based on cogeneration that was conducted by the Federal Ministry of Technology and Research in 1977. The study showed that between 17 and 25 per cent of the total low temperature heat demand of the FRG could be economically supplied by local municipal district heating options.

The development of long-distance heat transmission on the basis of coal-fired cogeneration stations and the use of waste heat has become one of the federal government's top priority energy goals.

In addition to important energy aspects, another objective of this policy is to support at least one-half to two-thirds of the previous mining capacity of the coal mining district of the Ruhr and the Saar to avoid excessive unemployment and social unrest.

To promote district heating and the development of coal-fired cogeneration stations, selective and massive financial assistance is being offered by the federal and the Laendar governments. Since 1975, the federal government has made available DM 300 million ($1 = DM 2.30) in support of long distance heat transmission and district heating via the energy research program. In the ZIP program the federal and Laender governments have made available DM 730 million for increased development of district heating with grants of up to 35 per cent of the investment costs.

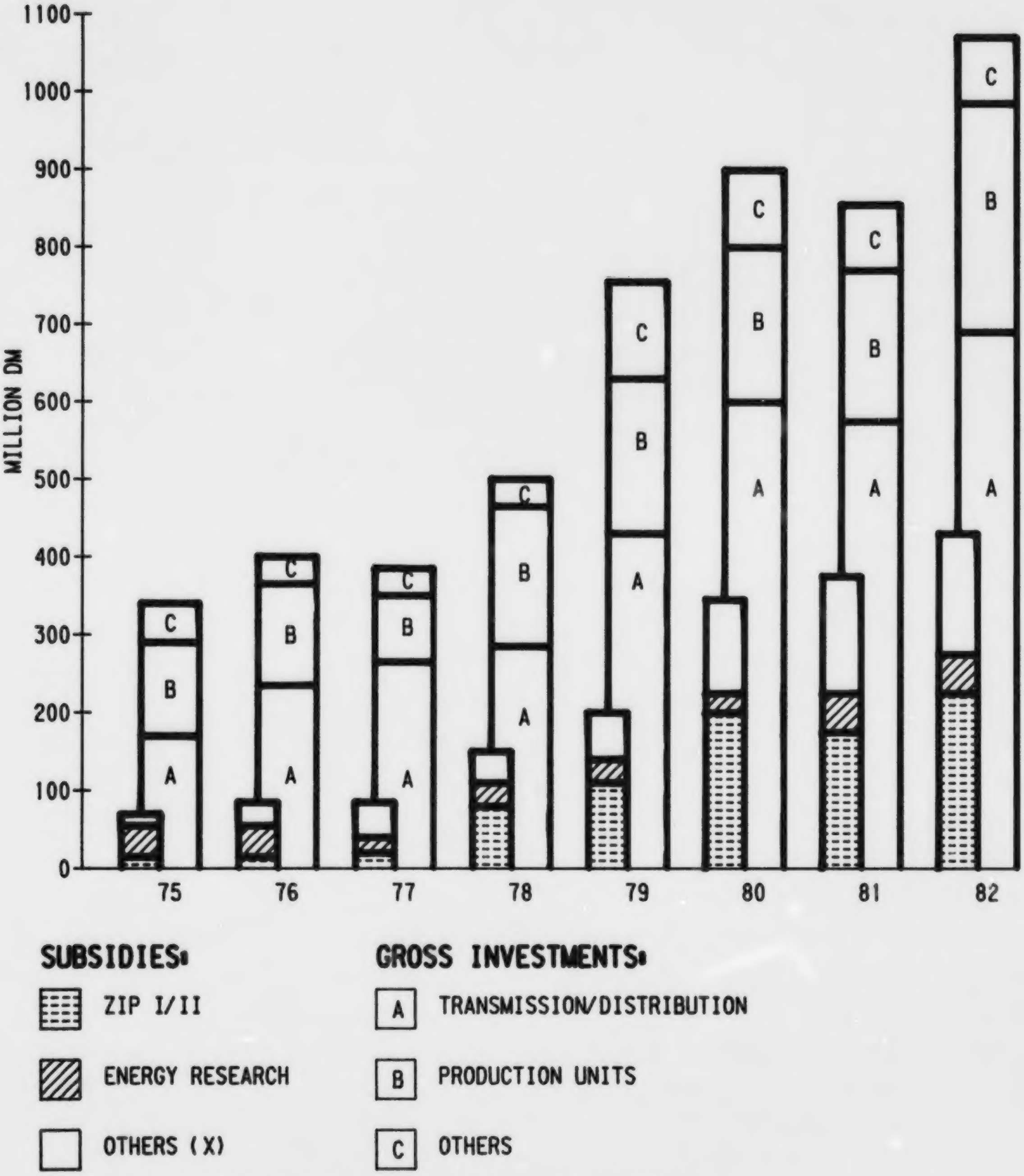
This program (ZIP-I) has been continued and extended by a new program (ZIP-II) in which the federal and Laender governments have jointly made available a total of DM 1.2 billion for the time period to 1986. The aim of the program is to trigger investments of more than DM 5.0 billion. Since the beginning of the program, it has been reported that there has been over-subscription of the available financial support. Furthermore, a grant of 7.5 per cent is provided for certain investments in the district heating sector under the provisions of the Investment Allowance Act. More than DM 600 million has been made available to date under this provision.

Since increased cogeneration is a prerequisite for the extension of long distance heat transmission, the federal government is promoting the construction of new coal-fired cogeneration stations with grants from the Power Generation Fund in accordance with Third Electricity Generation Law. In 1979, urged by the federal government, the public electric power industry and the industrial producers entered into an "Agreement on Cooperation in Electricity Production", which, in particular, improves the foundation for the utilization of industrial cogeneration plants.

A summary of various federal and Laender governmental subsidies for the development of district heating is given in Figure 4.2 with the subsidies also related to the gross investments in district heating in the FRG over the period 1975 - 1982.

The development of district heating is also indirectly promoted by means of subsidies and/or tax relief to owners of residential units when connecting to a district heating system. These subsidies are paid in accordance with the Modernization and Energy Conservation Act (ModEnG, 1978) when converting central heating and hot water systems in existing buildings. The owner can choose between a one-time 25 per cent subsidy paid immediately (excluding the connection fee) or deduct annually 10 per cent of the total connection cost (all costs covered) from his taxable income for the next ten years.

The Federal government has also tried to support the development of district heating by improving the legal position of the buyer. In 1980, the government issued an Ordinance Concerning General Conditions for District Heating Supply. This ordinance is an extension and a clarification of the general commercial law related to district heating and governs all district heating supply contracts, even those concluded before 1980.



X) SUBSIDIES ACCORDING TO THE INVESTMENT ALLOWANCE ACT, THE THIRD ELECTRICITY GENERATION LAW, AND THE MODERNIZATION AND ENERGY CONSERVATION ACT.

FIGURE 4-2
GROSS INVESTMENTS AND GOVERNMENTAL SUBSIDIES OF THE DISTRICT HEATING ECONOMY IN THE FRG.

Source: Professor Dr. H-J. Krupp, Deutsches Institut fur Wirtschaftsforschung, Berlin. Vortrag bei der AGFW am 23. Mai 1984 in Oberhausen

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.6 Conclusions

The reasons for development of district heating in Europe differ among countries, nevertheless, the common driving force has been the desire to produce a commodity - heat - with or without electrical power, which is cost-competitive with alternative heat production methods. Following World War II, concerns in some European countries over the adequacy of heat and power supplies led to development of district heating. Government encouragement, and in some cases coercion, through legislation and in some instances very significant financial assistance led to the development of many district heating and combined production systems at both the municipal and regional level. The reasons for government support have in some instances gone beyond the objectives of fuel conservation, and use of indigenous resources to achieve security of supply to include, as noted in the case of Germany, support to industry to maintain employment levels. During the decades that followed the war increased concern about the environment resulted in increased interest in district heating. The oil crisis in 1973/74 gave further incentives for energy conservation and oil substitution.

Many of these countries have developed energy plans in an attempt to rationalize the development of competing energy forms and it is interesting to note that one of the main objectives of these plans is to avoid the installation of competing capital intensive energy distribution systems in the same region. The significant traditional involvement of municipal government as well as regional and national governments in the energy sector appears to have had a positive impact on the development and implementation of these plans.

Most district heating systems have been developed and operated by organizations at the local level. In Sweden and Finland, almost all district heating systems are managed by municipal utilities. In Denmark, district heating systems are managed by local cooperative organizations as well as by municipal utilities. In Germany both municipalities and private companies have contributed to the development of district heating. Ownership is also mixed in the Netherlands.

With the exception of hydroelectric resources, Finland and Sweden are not well endowed with major indigenous energy resources and did not have access to natural gas resources until very recent years. In other European countries such as Austria, Belgium, Germany, Ireland, the Netherlands, Norway and the United Kingdom, the market penetration for district heating has not reached the same levels. During the post-war period, some of these countries could rely on hydroelectric power, coal, lignite or peat. In addition, the subsequent development of natural gas resources and the European gas grids provided another attractive energy alternative and as noted, its availability has seriously affected the level of penetration of district heating in countries like the Netherlands.

Natural gas has also been recently introduced in Denmark, Sweden, and Finland. As a newcomer in the heating market it has not yet affected the market share of district heating in these countries, however depending on its use either on a fuel for district heating or a fuel for individual heating systems its impact on the future potential for district heating could be positive or negative.

4.3 CANADIAN EXPERIENCE

431 GENERAL

District Heating systems in Canada are limited to relatively small sections of cities, university campuses, military bases, airports and the federal government buildings in the National Capital Region of Ottawa/Hull. Most of these systems use steam as the heat transport fluid but some federal government systems use HTHW.

Several industrial installations, particularly in the forest industry, produce and distribute steam for process and space heating. In some of these cases, cogeneration systems are operated.

Except for some private systems and remote communities, there are no DH systems utilizing cogeneration or incineration as heat sources for district heating, although a number of studies have been commissioned to investigate such systems. Incinerator plants have been built in Quebec City and Montreal which produce steam for industrial customers. Incinerator plants are operated in the Region of Hamilton-Wentworth Ontario, and Charlottetown, P.E.I. and produce high pressure steam. The Hamilton-Wentworth plant provides heat in the plant and generates electricity. In the Charlottetown plant, steam is used to heat two nearby hospitals.

Many of the existing heating plants were originally designed to burn coal but most boilers have been modified to burn oil and/or natural gas. While a number of studies for DH projects based on the use of wood and coal fuel have been performed, the proposed projects, for various reasons, have not been implemented.

Most DH public utility systems use steam as the heat transport fluid and except for the CN system in Montreal, the steam DH systems return little or no condensate. On the other hand, many of the government and institutional block central steam systems maintain condensate return systems. The steam and HTHW systems use a variety of piping systems to distribute the heat. Tunnels have been used frequently because they provide access to the pipes for repair, maintenance and retrofit work. However, tunnels are expensive to construct and, consequently, many systems are direct buried or installed in a concrete culvert.

As a result of large natural gas and oil transmission systems in Canada, gas and/or light oil are readily available to most consumers and the price differential between the fuel costs for the individual and DH consumer has been reduced considerably. In the sixties, a DH utility could obtain heavy oil at approximately 40 per cent of the price paid by the individual consumer for fuel oil with the same heat content. This compares with a corresponding ratio of approximately 78 per cent for fuel oil and 68 per cent for natural gas at current prices. It is apparent that with this diminishing fuel price advantage that the operating efficiency of the DH system must be somewhat better than the individual heating systems to offset the high cost of installing and maintaining a DH system if the system is to remain viable. Unfortunately, the average operating efficiency achieved by many of the existing DH systems is approximately the same as that achieved by most individual home heating systems and, is in fact less than the efficiency achieved by many heating systems in office and apartment buildings. In addition, electricity is making increasing inroads into the space heating market in some parts of the country. In the face of the increasing competition in the energy sector DH heating will be viable only if the overall operating efficiency of the DH system can be significantly improved and the fuel price advantage, that DH systems had previously enjoyed, is regained through the use of lower grade, lower cost fuel that cannot be economically used in individual systems.

During the past decade, there has been a renewed and significant interest shown by the various levels of government, the engineering profession and industry in district heating. Although studies have indicated that several Canadian projects appear technically and financially attractive, none have been built except for the LeBreton Flats pilot project in Ottawa.

As noted earlier the availability of low cost energy alternatives such as natural gas and electricity through established distribution networks has had a detrimental effect on the acceptance and development of district heating. With the development of large surpluses of these energy forms, new energy technologies such as district heating are likely to be faced with increasing competitive pressures.

While the federal and provincial governments play significant roles in the energy sector, municipal governments, which appear to have taken leadership roles in district heating initiatives in Europe and the United States, are with the exception of municipal electric utilities in Ontario, not significantly involved in energy management in Canada. There are very few municipalities involved in the production and distribution of primary or secondary energy forms that might be compatible with development of district heating.

Federal government initiatives in the energy sector in recent years have been oriented towards promoting energy conservation and shifting off oil in order to achieve energy self-sufficiency rather than promoting any specific alternative energy form. Grants provided under the Canadian Oil Substitution Program have been effective in reducing oil consumption but the major beneficaries of the policy of oil substitution have been the other conventional energy sources, natural gas and electricity which have absorbed most of oil's lost market share. The Forest Industry Renewable Energy Program, however, is an example of a program oriented toward the use of wood waste (and new incineration) as an energy source. There is some direct financial support available through programs like the Atlantic Energy Conservation Investment Program and indirect assistance in the form of accelerated capital cost allowances for energy conservation and oil substitution technologies. For the most part, however, direct support for alternative technologies has been in the form of feasibility study support and support for demonstration projects through the Conservation and Renewable Energy Demonstration Program (more recently ENERDEMO).

In addition responsibilities in the energy sector are divided between the federal and provincial governments. This makes the type of detailed national and regional planning and rationalization of competing energy forms (which might favour district heating in some instances) that has taken place in some European countries difficult to accomplish in Canada.

432 EXISTING DH SYSTEMS

There are nine public DH systems in Canada and approximately 100 DH systems owned by government agencies and institutions. The major municipal or municipally franchised systems are located in Montreal, Toronto, London, Winnipeg and Vancouver. They were developed to supply heat to commercial buildings and some industry in the cities' core. Major government systems are owned by Public Works Canada with eleven DH systems in Ottawa/Hull and the Department of National Defence which operates systems on each military base across the country. In addition, Transport Canada owns and operates DH systems on most major airports. The Northern Canada Power Commission, a Federal Government crown corporation owns and operates HTHW systems in Inuvik and Frobisher Bay, in the Northwest Territories.

A brief analysis has been performed on all Canadian DH systems operated by public utilities and a general assessment has been made of other systems operated by universities and by federal government departments and agencies. Most of the information for this analysis has been obtained from reports, some first hand experience and discussion with some operators of these DH systems.

.1 Public Works Canada (PWC)

PWC owns and operates eleven DH systems in Ottawa/Hull. The heating fluid for eight systems is high pressure steam and HTHW is used in the other three systems. The total installed capacity is 500 MW and the annual output is 3120 TJ.

The main plant, commissioned in the early twenties, is located in central Ottawa and supplies steam to government buildings in the core area. The system has been expanded several times since World War II and further expansion in the core area is planned in the immediate future.

The original fuel for all but the last two plants was coal. However, all boilers, except the Hull plant, were modified to burn Bunker C oil and natural gas in the sixties with natural gas currently the principal fuel. While coal is used in the Hull steam plant, conversion studies are underway. It is reported that the overall efficiency of one PWC DH system is 71 per cent, however, the operating efficiencies for the other DH systems were not available.

Most of the transmission and distribution systems are direct buried or installed in tunnels. Condensate is returned to the plant in all but one system. Fibreglass was used for the condensate lines to overcome corrosion problems but, failures have occurred in these lines making this system unsuitable to return condensate.

.2 Department of National Defence (DND)

The Department of National Defence operates DH systems on each military base across the country. Thirty-five of these systems are high pressure steam, however, a HTHW system is installed at Camp Gagetown, New Brunswick and a relatively small HTHW system is installed at the Shannon Park base in Halifax.

The HTHW systems were designed in the fifties and overall efficiency is estimated to be between 50 and 60 per cent, despite the fact that most condensate is returned to the heat plant. The relatively low efficiency is attributed to heat loss from the distribution system during periods of low loads.

.3 Northern Canada Power Commission (NCPC)

The NCPC is a Federal crown corporation which owns and operates DH systems in the towns of Inuvik and Frobisher Bay in the Northwest Territories. These systems provide heat to 75 per cent of the two communities of 2,700 and 2,000 respectively. The heat transport fluid is HTHW supplied at 175°C and returned at 130°C.

The heat distribution system consists of extra heavy pipe with a thick application of insulation. The pipes are installed in utilidors which are supported on posts that have been sunk into the permafrost, or rest on rock if it is available.

The overall thermal efficiency is understood to be low. This is confirmed to some extent by the fact that the rate for heat charged by the Commission is sufficiently high that some customers opt for individual heating systems notwithstanding the high cost of fuel oil, (approximately $.50/L).

.4 Public DH Systems

.41 Montreal CN Rail owns and operates a public DH system providing steam to the core area surrounding the CN Rail Station in Montreal. It provides heat through a high pressure steam system to 13 major buildings with an area of one million square meters. Steam is generated in five boilers with a firm capacity of 110 MW at a pressure of 2600 kPa and an annual outut of 660 TJ [135].

The steam is distributed though pipes located in a tunnel or building space and most of the condensate is returned through the same passage ways. The line losses have not been established but the overall efficiency is 65 per cent.

There are many large buildings located relatively close to the heating plant such that there is potential to expand the heating load of the system threefold. Because the transmission and distribution network is accessible, retrofit work could be done at reasonable cost. In view of the plant location, the possible use of municipal solid waste (MSW) fuel, the accessibility of the transmission and distribution network and the potential heat load, the expansion of the system appears to be feasible.

A joint Energy, Mines and Resources Canada (EMR)/Quebec Ministry of Energy study assessed the expansion of the DH system by adding heat from municipal refuse incineration. It was intended that the incinerator plant would generate most of the steam required for the customers of the systems. The study report was completed in 1980 but the proposed project was not implemented.

.42 Toronto The Toronto District Heating Corporation (TDHC) steam DH system supplys 1900 TJ/per year to about 100 downtown customers, five hospitals and four teaching facilities [111], [116]. The TDHC was formed by an Act of the Ontario legislature in November, 1982, and it assumed responsibility for the operation of the system from the Toronto Hydro Electric System in February, 1984. The system is supplied from the Toronto Hospital Walton Street plant providing base load capacity, and the former Toronto Hydro Electric System Pearl Street plant provides peaking capacity. It is intended that by 1986 the University of Toronto plant will be used for peaking capacity and the Pearl Street plant will be shut down. These units are fuelled primarily with interruptible natural gas.

The Pearl Street plant chimney creates an environmental problem (particularly when the fuel is oil) because it discharges gases at a much lower level than many of the surrounding buildings. When natural gas is used, the situation is acceptable to the Ministry of Environment. The construction of the proposed incineration plant would provide a solution to garbage disposal and a renewable resource for fuel and would allow the Pearl Street plant to be phased out. The Walton Street and University of Toronto plants would then be used for peaking and standby.

At the present time, the steam system, fueled by natural gas is under significant price competition and the steam load is declining. The decline is not the result of conversions but rather due to demolition of existing buildings served by steam. The continued economic viability of the system is contingent on the construction and operation of the proposed incineration plant as a low cost source of heat. It is understood that environmental hearings for the plant were to begin in January, 1985, but they have been delayed. If approval is obtained, the plant could provide steam to the system in 1988.

.43 Winnipeg Winnipeg Hydro, a municipally owned public utility, produces steam at its Amy Street power plant and, in 1983, the utility sold 420 TJ to 215 customers at an average rate of $8/GJ. Of the total steam generated, about 14 per cent is produced by boilers heated with surplus electricity from hydro sources. The balance is produced in coal-fired boilers. The steam is used for heating commercial and institutional buildings in downtown Winnipeg. Very little condensate is returned.

Pollution control equipment is required to reduce emissions and other plant upgrading is also required. The total estimated capital cost for these modifications including required distribution system upgrading was approximately $20 million 1982 dollars.

Considering the DH system's current operating deficit, escalating fuel costs, the costs of required modifications to the Amy Street plant, and a desire to review the management of municipal solid waste within the City, a study to examine the economic viability of district heating for the central area of the City of Winnipeg has been undertaken [230]. The Manitoba/Canada Conservation and Renewable Energy Development and Demonstration Agreement provided the necessary monetary assistance to allow a study to proceed. Funding was provided equally by the Federal Government, the Province of Manitoba and the City of Winnipeg.

The study was commissioned in two phases. Phase I of the study was of limited scope and intended to provide a preliminary indication of viability. This phase of the study, completed in October 1982, indicated that a viable system was possible and that significant benefits could accrue to the City of Winnipeg. The second phase study was completed in December 1984 and recommends the construction of a MSW incinerator project. This project would supply most of the steam for an upgraded and expanded DH network using steam as the heat transfer fluid. The upgraded new system would have a potential subscriber heat load of 1400 TJ per year.

.44 Vancouver A privately owned steam DH system regulated by the BC Energy Commission provides heat to some 90 buildings in the downtown area. The heat plant is located next to the new dome stadium with limited room for expansion.

Four gas-fired (oil standby) boilers produce 180 TJ of steam at 1380 kPa that is delivered through 4.8 km of distribution mains. The system has been continuously upgraded and expanded and a 600 m extension of the distribution system was constructed in 1982. The total plant capacity is 128 MW with a firm capacity of 117 MW. No condensate is returned from the subscriber to the heating plant because the condensate pipes have failed from corrosion. The annual operating efficiency is 63 per cent. Future changes will likely involve the use of alternate fuels. One of the proposals under consideration is fluidized bed combustion of coal or refuse derived fuel. Although the system has experienced operating difficulties in the past, capital expenditures not only to expand the system, but also to improve system efficiency continue to be made with the objective of attaining a higher system efficiency.

.45 Ottawa The Le Breton Flats project is a relatively small pilot project but nevertheless, a complete system. It was initiated by Canada Mortgage and Housing Corporation (CMHC) and financed by EMR and the Ontario Ministry of Energy to investigate the technical aspects of heating a housing community using European type hot water DH technology. Therefore, the most important engineering features are the distribution system and the transfer of heat from the distribution system to the space and domestic hot water systems in the buildings. In order to measure and monitor the thermodynamic performance of the complete system, metering devices were installed in each building.

The capacity of the heating plant is 2.5 MW which is provided by two hot water generators. To minimize the operating costs of this small system, the plant was designed to operate unattended.

The maximum operating temperature of the system was established at 99°C in order to minimize heat losses. It was designed to allow operation at the lowest possible distribution temperature that will satisfy the heat load at any given time in order to minimize heat losses. The maximum design operating pressure is 600 kPa [109].

The design of the distribution piping network is in general accordance with European practice. The main design features are thin wall steel pipe complete with high density, factory applied, polyurethane insulation contained within a heavy polyethylene casing to protect against ground moisture, and backfill. Thermal expansion is accommodated by concrete anchor blocks, expansion chambers at elbows and expansion loops. To enable purging and draining of the primary distribution system, the piping was sloped to drain cocks.

Water flow meters were installed in some buildings to measure the hot water flow to individual suites. These are used in conjunction with the heat meters during the metering and monitoring program to assess individual heat usage and to determine the effectiveness of flow meters to measure heat consumption.

The DH system was completed in 1981, and has operated satisfactorily over three complete seasons. It is not known what changes in the method of operation have been considered or undertaken as a result of the monitoring program.

The operating efficiency of the Le Breton project compares favourably with European experience. The values recorded shortly after the project was commissioned early in 1982 were:

Maximum plant efficiency	85 percent
Minimum plant efficiency	77 percent
Maximum distribution efficiency	96 percent
Minimum distribution efficiency	93 percent
Maximum overall efficiency	81 percent
Minimum overall efficiency	71 percent

.5 Carleton University

The DH steam system at Carleton University in Ottawa is typical of the DH systems that supply heat for most Canadian universities. The plant was built in 1963 and consists of three natural gas/oil-fired boilers with rated capacities of 12, 20 and 26 MW. The maximum load is 25 MW and consequently, the largest boiler is rarely used.

Losses in the distribution network are 34 per cent and the annual efficiency of the complete system is 56 per cent. This is a low value in view of the fact that the system is well maintained and operated and that 90 per cent of the condensate is returned to the boiler.

A waste heat recovery boiler has recently been commissioned. It recovers heat from the flue gases and transfers it to the feed water make up and to heat the combustion air. It is intended to install a heat pump to operate in conjunction with the heat recovery boiler. This combined system will recover most of the latent heat of the water condensed from the flue gases. However, before this can be achieved, it will be necessary to change part of the steam distribution network to MTHW to provide a heat sink within the return water of the distribution network at a temperature at or below 60°C. If, the change from a steam to MTHW distribution network is successful, the complete distribution network will be changed to MTHW.

433 PROPOSED DH SYSTEMS

A number of studies of the feasibility of installing new DH systems in a number of Canadian cities have been carried out over the past decade including Charlottetown, Halifax, Mississauga, Sarnia and Edmonton and a number of remote communities. Several of these studies are discussed briefly below.

.1 Halifax

A major DH study involving cogeneration in the Nova Scotia Power Corporation Water St. thermal generating station was performed in the mid-seventies [222]. This project is presently inactive because the thermal electric plant that was to be the heat source has been shifted from base load service to standby as the Corporation has shifted from oil to coal-fired generation.

.2 Mississauga

The Ontario Ministry of Energy sponsored an energy management study for the Mississauga City Center. The study indicated that since 90 per cent of city center growth has yet to occur, planning decisions on energy management issues made at the present time could result in significant future benefits. At the end of a 25 year span, Mississauga City Center will be consuming approximately 2000 TJ of heating and electrical energy per year. The study estimated that a district heating and cooling system would save about 20 per cent of the overall operating cost when compared to individual building systems and should be developed. No further action has been undertaken since the completion of the study in 1982.

.3 Edmonton

Edmonton Power, a municipally owned electric utility, has conducted two studies to provide cogeneration and district heating for the core area of Edmonton [228]. The first study involved the Rossdale plant in downtown Edmonton as the heat source. This concept was abandoned because the operating mode of the plant, which uses natural gas, has changed to a peaking role and it will eventually be retired. The second study involves the Genesee plant which is under construction 64 km south of Edmonton. This plant is located near a coal field which will be the source of the fuel. The feasibility study indicates that it would be technically and financially attractive to transport cogenerated heat by a supply and return piping system to the Edmonton core area.

The problems of implementing a DH project of this magnitude are well known but if this project was to become a successful operation, it would be a milestone for district heating in North America. The transmission line would not only be the longest in North America, but it would be longer than most in Europe.

Due to reduced electrical load growth in Alberta completion of the Genesee plant has been deferred at least two or three years and thus the earliest date for heat delivery would be in the late eighties. It is not known how this will affect Edmonton Power's district heating plans.

.4 Tumbler Ridge

Tumbler Ridge is a new town in north-eastern British Columbia created to house workers of the new coal mines which are part of the massive North-East Coal Project.

In October 1982, a preliminary report commissioned by CMHC, indicated that a LTHW district heating system was economically feasible for this community of 5,000 people [59]. It was the most promising option because low cost coal was immediately available, natural gas was at a distance of 100 km, it was a greenfield site with favourable soil conditions, and due to the cold climate had a relatively high heat consumption.

In April 1983, a conceptual design utilizing a steam boiler plant and a MTHW system was prepared. The estimated capital cost for the total system was $14,700,000 and the estimated nominal internal rate of return on this investment was more than 20 per cent. The project did not proceed for non-technical reasons.

.5 Remote Communities

A number of studies have been performed to provide a form of cogeneration and district heating for remote communities. Approximately ten projects have been built in the Northwest Territories and one has been built to heat a school for the native community at Oxford House in Manitoba. Much experience has been obtained from these projects and it is expected similar projects will be implemented in more communities. NCPC has a policy to provide waste heat at no cost from its diesel electric generating sets. However, it must be reimbursed by others (usually the Federal Government) for the cost of all work performed in retrofitting the power plant. NCPC also maintains heat exchanger equipment in the plant at no cost but the distribution piping and subscriber equipment must be maintained by others, usually the community. It should be noted that there is almost no fuel consumption penalty when using waste heat from a diesel engine even if heat is extracted from the exhaust gases. NCPC insists that heat exchangers installed in the exhaust gas must be sized for low pressure loss and the commission must be responsible for all retrofit design work in the plant.

434 CONCLUSIONS

A number of factors that fostered the development of district heating in many European countries were identified in the earlier discussion such as;

(i) the absence of low cost conventional indigenous energy resources including oil, natural gas, and hydroelectric resources.

(ii) government structures that permitted detailed integrated planning by national regional and municipal governments in the energy sector.

(iii) a long tradition of cooperative action at the local level which improved the acceptability of local district heating projects.

(iv) an apparent willingness on the part of the populace to accept controlled access to energy alternatives and the principle of compulsory connections.

(v) substantial government financial and legislative encouragement (and coercion) for the development of district heating to promote energy efficiency, the use of indigenous resources and in some cases industrial support.

It is clear that none of these factors currently exist in Canada. While government has played an active role in directing consumption away from particular energy resources (oil), it has been left largely to competitive market forces to determine what alternative energy forms will satisfy that displaced demand. In this regard Canadian activities and experience has not been dissimilar to that of the United States.

Canadian experience with existing steam based DH systems is strikingly similar to the experience in the USA. These systems with overall operating efficiencies of 50 and 60 per cent are increasingly uneconomic particularly when operated with conventional fuels.

It would appear that unless DH systems can achieve an overall efficiency of 75 to 80 per cent while using a fuel source with a price considerably lower than the fuel used by an individual system, the ability of DH systems to compete against relatively efficient individual systems, is rather bleak. This observation leads to the conclusion that if there is to be a renaissance of district heating in Canada, it will, as in the United States, have to be based on European DH technology and low cost, low grade fuels, possibly in concert with cogeneration.

PART FIVE

THE CANADIAN ENVIRONMENT

PART FIVE - THE CANADIAN ENVIRONMENT

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5.1 GENERAL

An assessment of the realistic potential for the development of district heating in Canada must recognize the more important characteristics of the Canadian space heating market in which the district heating technology must operate and compete.

In common with other energy distribution systems such as natural gas and electricity, district heating is a highly capital intensive technology. As such, it requires a large and relatively stable cash flow (and consequently a large heat load) to support the high fixed costs associated with the capital investment in the system. In addition, two of the three components of a district heating system, the heating plant and distribution network, are significantly affected by economies of scale, with the result that the delivered cost of heat from a district heating system will tend to decrease with increasing heat loads and heat densities. The effects of scale can have a dramatic and positive impact on the ability of district heating to compete with established conventional energy forms. Consequently, the cost of district heating is affected by many more variables than individual heating systems. For example, the cost of individual heating systems is essentially independent of the number and size of individual houses and their dispersion over a given land area, i.e. the heat load, the heat load density and the connection density. However, district heating distribution system costs could be dramatically affected by the absolute magnitude of the total heat load and the frequency and dispersion of the household connections.

District heating studies therefore, tend to be complex exercises and economic feasibility can only be established through analysis of a number of interdependent technical and economic variables.

5.2 DISTRICT HEATING PARAMETERS

The information that is required to define the environment in sufficient detail to be able to evaluate and establish the technical and economic feasibility of district heating in a specific community will typically include, among other things, information on the total heat load, the heat load densities, connection densities, soil conditions, alternative energy costs and existing heating systems. While it may be possible to obtain this information for a single community it is clearly impractical to contemplate compiling such detailed information for a study of this general nature. Consequently the approach taken has been to identify the major demographic and climatological factors that are likely to maximize the incentive to adopt district heating. The parameters that have been chosen are:

(i) climate
(ii) population and population density
(iii) existing heating equipment
(iv) alternative energy forms.

521 CLIMATE

.1 General

The two climatological parameters that are of greatest importance from the point of view of district heating are annual degree days (DD) and outdoor design temperature. These weather data can provide a means of estimating relative heat consumption and demand for the different climatic regions of Canada and identifying those areas likely to have relatively higher heat loads due to climate.

.2 Annual Degree Days, Design Temperature and Temperature Difference

The degree day statistic is a measure of both the time period, or duration, that the average daily outside temperature falls below a base temperature and the amount by which it falls below that base temperature. The standard base temperature (the outside temperature above which a building need not be heated) is 18°C. On a single day when the average outside temperature is 13°C, the number of degree days for that day is calculated as:

$$1 \text{ day} \times (18 - 13)^\circ\text{C} = 5 \text{ degree days}$$

The annual degree days statistic is the sum of the daily degree days recorded over the period of a year. Annual degree days give an indication of the energy required for space heating. Therefore, if a house is moved from one area to another area that has twice the number of degree days, all other things being equal, its energy consumption for space heating should double. Energy consumption may vary with solar and wind effects as well as with regional building practices and occupants' lifestyles. The impact of these factors on heat consumption is very difficult to quantify and is probably small compared to total consumption. Therefore, the impact of climate on relative energy consumption for space heating is, for purposes of this study, based on annual degree days.

Outdoor design temperature (t_d) is a measure of the coldest temperature that can be expected in a region. For example, a 2½ per cent design temperature of -30°C indicates that the temperature will be lower than -30°C only 2½ per cent of the heating season (about 54 hours). Another commonly used statistic is the temperature difference (TD) measured as the difference between the base temperature and the outdoor design temperature ($TD = 18^\circ C - t_d$).

Design temperature and temperature difference provide a means of estimating the maximum rate at which heat will be required and therefore the size or capacity of the heating plant needed to supply that heat demand or load. For example, an area with an outdoor design temperature of -2°C (TD = 20°C) will, all things being equal, require a heat plant half the size or capacity of an area with an outdoor design temperature of -22°C (TD = 40°C).

The relationship between annual degree days and temperature difference has been estimated based on recorded data for 145 Canadian cities and towns that experience annual degree days between 3000°C and 6000°C and is given as:

$$TD = 4.56 + .0078\ DD \qquad (1)$$

The correlation coefficient for this data set was 0.875, indicating a reasonably strong linear relationship between these two variables. The trend line, as well as the actual values for a number of selected Canadian cities are presented in Figure 5.1. On the basis of this analysis the impact of climate on relative heat demand will, for study purposes, also be based on annual degree days. While such a simplifying assumption is necessary for a study of this nature, it is clear from the degree of scatter that can be seen on Figure 5.1 that the relationship is far from exact and consequently such an assumption may not be appropriate for site specific studies.

.3 Load Duration Curves

A heat load duration curve is a graph of heat demand plotted against the number of hours that the demand is exceeded and can be developed for daily, weekly, monthly and annual time periods. A typical annual load duration curve is shown in Figure 5.2. Looking at the curve, if only space heating requirements are plotted, the demand will be zero when the outside temperature is equal to or greater than the

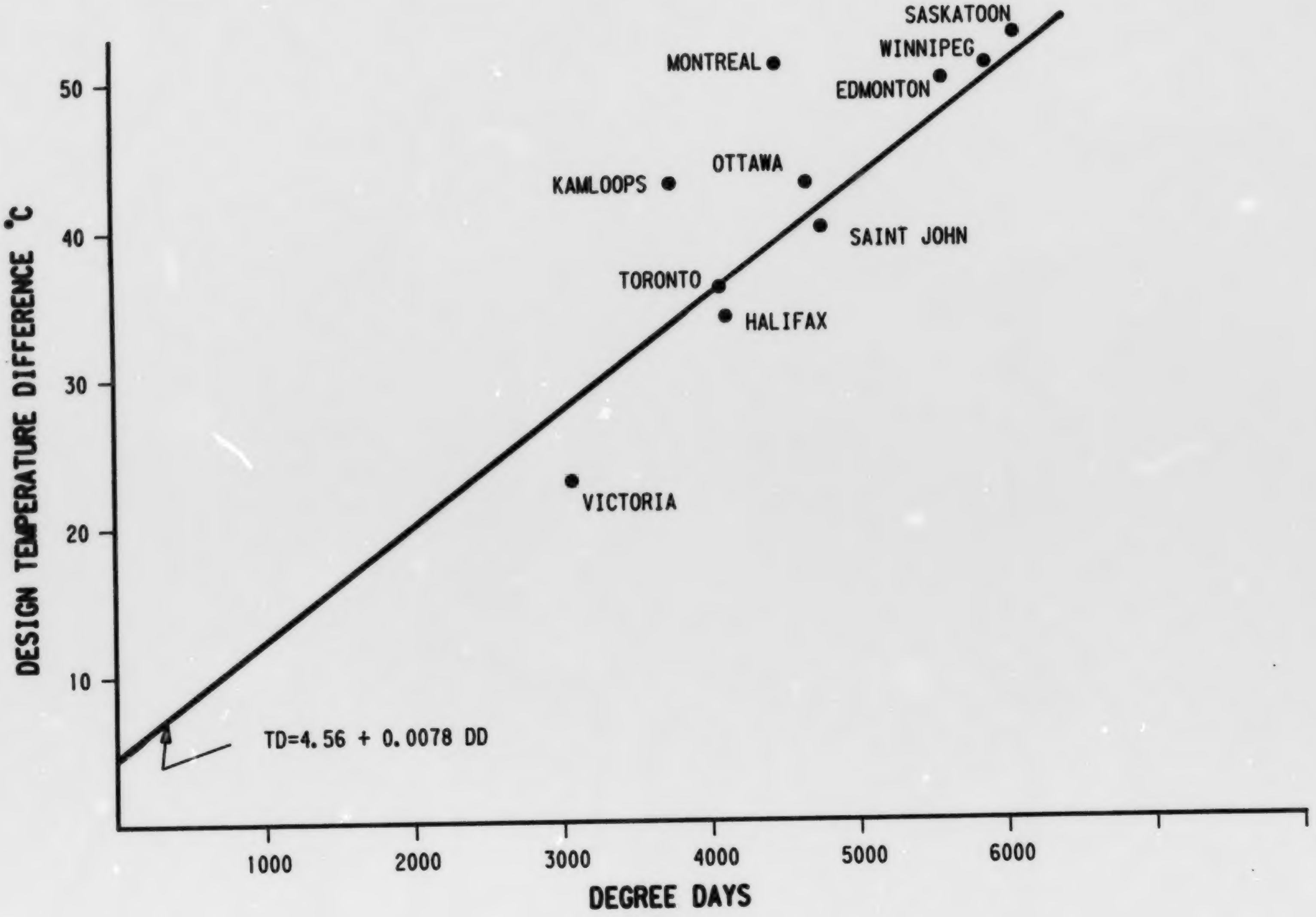
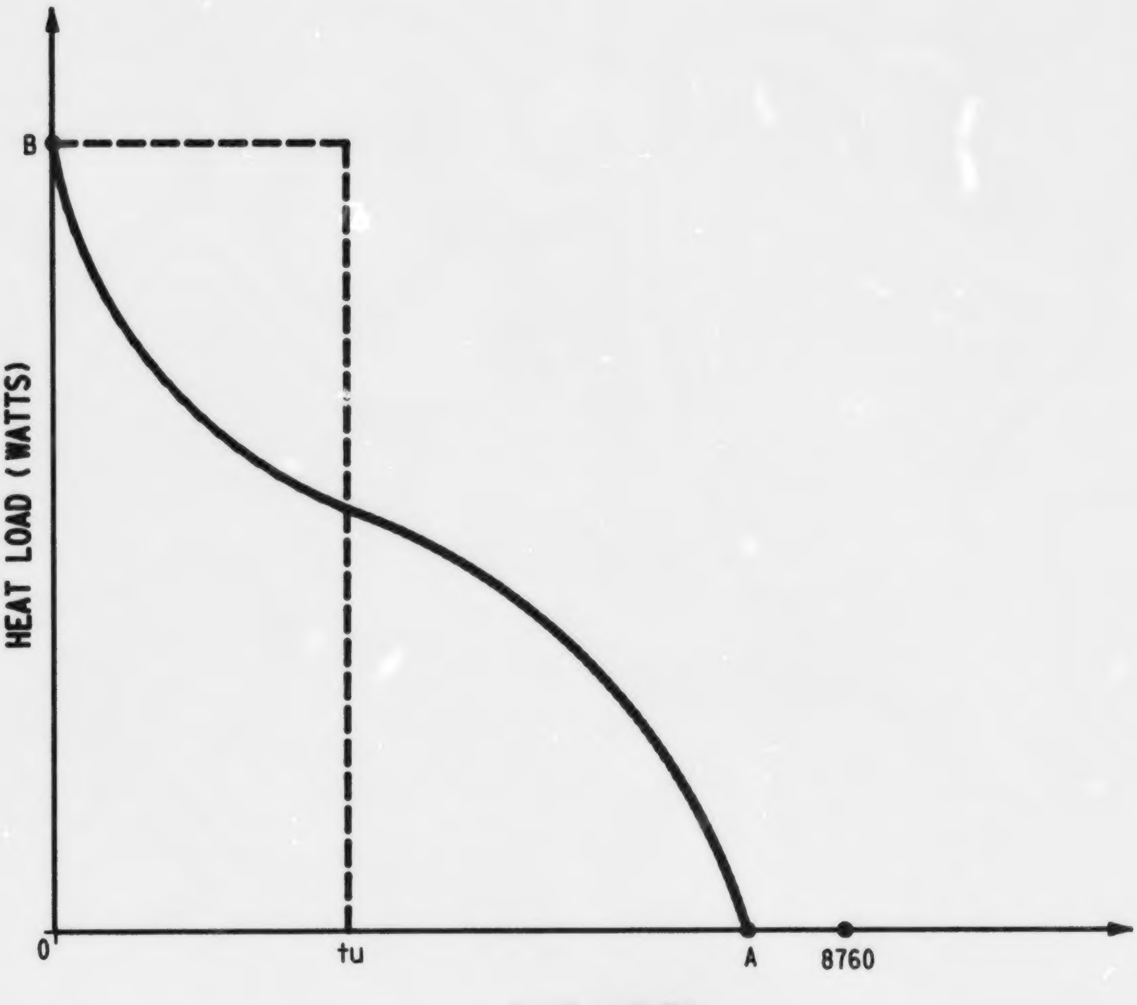


FIGURE 5-1
RELATION BETWEEN TEMPERATURE
DIFFERENCE AND DEGREE DAYS



t_u=UTILIZATION TIME = $\frac{\text{ANNUAL HEAT REQUIREMENTS}}{\text{MAXIMUM HEAT DEMAND}}$

FIGURE 5-2
TYPICAL LOAD DURATION CURVE

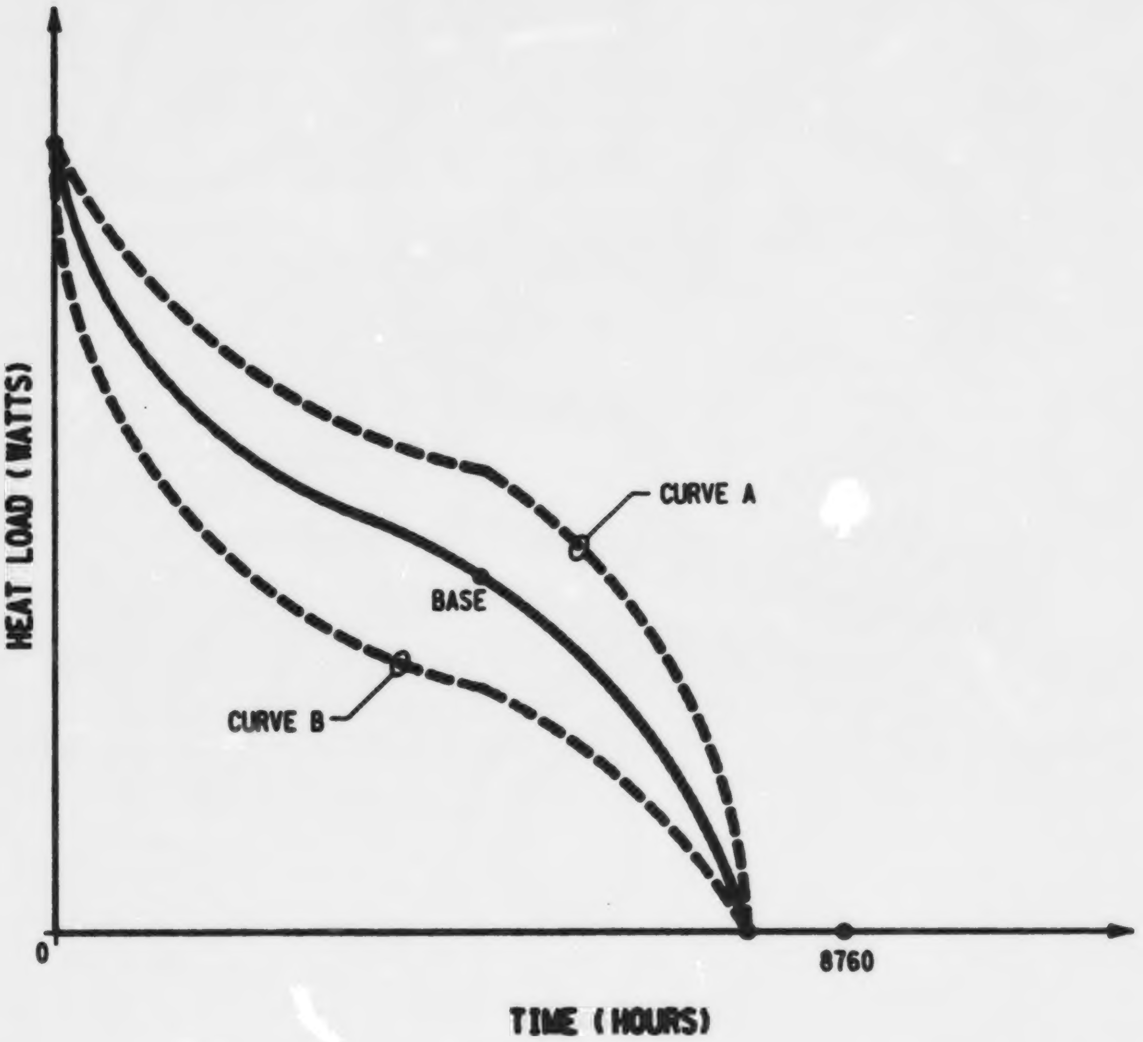
[100,77]DSS52 .DGN

base temperature (Point A) and at its highest value (Point B) when the outside temperature is at its lowest value, typically the design temperature. The shape of the curve between these two points will be a function of the duration of intermediate outside temperatures between the minimum outside temperature and the base temperature. The area under the curve represents the total annual energy requirement for space heating. A simple method of describing this area is to use the concept of utilization time. Utilization time is the number of hours at full capacity a plant must run in order to provide the same energy output as it would under normal operating conditions. The utilization time (t_u) is given by the formula:

$$t_u = \frac{DD * 24 \text{ hours/day}}{TD} \qquad (2)$$

In order to study the effects of varying degree days at the same outdoor design temperature, consider Figure 5.3. If, at the same outdoor design temperature, the number of degree days is increased, the energy consumption and utilization time increases (Curve A) and, all other things being equal, the unit cost of heat from a DH system will tend to decline. On the other hand, decreased degree days will result in decreased consumption and utilization time (Curve B) and a relatively higher unit cost of heat delivered from a DH system.

Using equations (1) and (2), the utilization time for 4500 annual degree days is approximately 2700 hours. With the range of annual degree days generally applicable to Canada (3000 - 6000) this value stays reasonably constant within a range of ±5 percent. In this study, it has been assumed that utilization time will be approximately 2,700 hours. For locations that fall below the trend line in Figure 5.1, the utilization time will be higher than 2700 hours and conversely for locations that fall above the trend line the utilization time will be lower than 2700 hours and this will have an effect on the viability of district heating.



[100,77]DSS52 .DGN

FIGURE 5-3
LOAD DURATION CURVE
SHOWING VARIATIONS IN DEGREE DAYS
AT SAME DESIGN TEMPERATURE

The building stock of cities changes in many ways as cities grow in population, with larger office and apartment buildings becoming a greater proportion of a city's building stock.

The difference in the amount and type of building stock between a small and a large city that occurs because of differences in types of activity, not only affects the total heat consumption but also the relative heat density, both of which will have an effect on the feasibility of district heating. Larger office and apartment buildings will increase both heat density and heat loads as well as reduce the connection density. For example, a block of single family dwellings on lots 15 m wide and each using 100 GJ per year that are served by a DH system will require a small pipe with many connections to it. A block of highrise apartment buildings served by a DH system will require a larger distribution pipe, will have fewer connections to the distribution system and will have a higher overall energy consumption. These factors will make the delivered unit cost of energy lower for the block of apartments. The larger distribution piping will be more costly for the apartment block, but this increase in cost will typically be less than the costs incurred to service the greater number of connection points and lower energy requirements of the single family dwellings. Therefore, the increased heat densities as well as the decreased connection density of a large city will make district heating more attractive than for a smaller city.

523 EXISTING HEATING EQUIPMENT

The investment for end user heating equipment is an important part of the total cost of a DH system and retrofit costs to convert a building to district heating are significantly affected by the type of existing heating system (forced air, hot water, electric baseboard). For example, a house with electric baseboard heating will require a complete overhaul of its heating system and the installation of a fancoil unit or heat exchanger and either forced air ducting or piping and hydronic baseboards. A house with a hot air or hydronic system can use the existing ducting or piping. As will be discussed in Part 6 the difference in cost can be substantial. Table 5.1 shows the proportions of existing urban residental heating equipment types by province.

As can be seen from the table, both Newfoundland and Quebec have a high percentage of electrically heated residences. This indicates that conversion of subscriber heating systems to accept district heating will likely be more costly in these provinces than in a province like Prince Edward Island which has a low proportion of electric heat and a relatively high proportion of hydronic heating systems.

In general, office buildings can be converted from individual heating systems to district heating systems at relatively low cost. Exceptions to this are office building systems which distribute low pressure steam throughout the buildings and all-electric heating systems.

524 ALTERNATIVE ENERGY FORMS

There are a number of different fuel types or energy currencies with which district heating must compete in the residential

TABLE 5-1

Existing Urban Residential Space Heating Equipment - 1981
(Percent of Dwelling Units)

Province	Hydronic	Forced Air	Electric	Other
Newfoundland	20	31	37	12
Prince Edward Island	60	30	3	6
Nova Scotia	43	40	11	6
New Brunswick	34	37	23	6
Quebec	26	25	40	9
Ontario	25	57	15	3
Manitoba	16	62	19	3
Saskatchewan	18	74	4	4
Alberta	19	73	4	4
British Columbia	21	55	19	5
Canada	24	49	21	6

Source: Statistics Canada, "Occupied Private Dwellings - Selected Characteristics", Catalogue #92-932.

and commercial space heating market such as oil, natural gas, electricity, coal, wood and others. Figure 5.4 presents the total annual energy consumption by the residential and commercial sectors in Canada by major fuel type over the period 1971 to 1981. It is clear from Figure 5.4 that the principal energy forms used by the residential and commercial sectors are oil, natural gas and electricity. Figure 5.4 also indicates that the growth in energy consumption in these sectors has been very modest over the period. The annual compound growth rate over the period was only slightly over 1¼ per cent and absolute consumption declined from 1979 to 1981. In addition, due to its higher cost, the effects of the Canadian Oil Substitution Program, and the increased marketing efforts of the natural gas and electrical industries, the market share of oil has declined from almost 50 per cent in 1971 to about 28 per cent in 1981 and it continues to decline.

Considering the relative prices for natural gas, electricity and oil, the opportunities for district heating will, all things being equal, be greater in those parts of the country where oil continues to maintain a large proportion of the space heating market. Table 5-2 shows the share of the urban residential space heating market (expressed as a per cent of dwelling units) held by the principal fuel types in each province. Natural gas tends to be the dominant fuel type in the west, oil and natural gas or electricity hold significant market shares in central Canada and Newfoundland and oil is the dominant fuel in the Maritime Provinces. Consequently the price competition facing district heating will, at least until natural gas from the Scotian Shelf is commercially available, likely be weakest in the Maritime Provinces.

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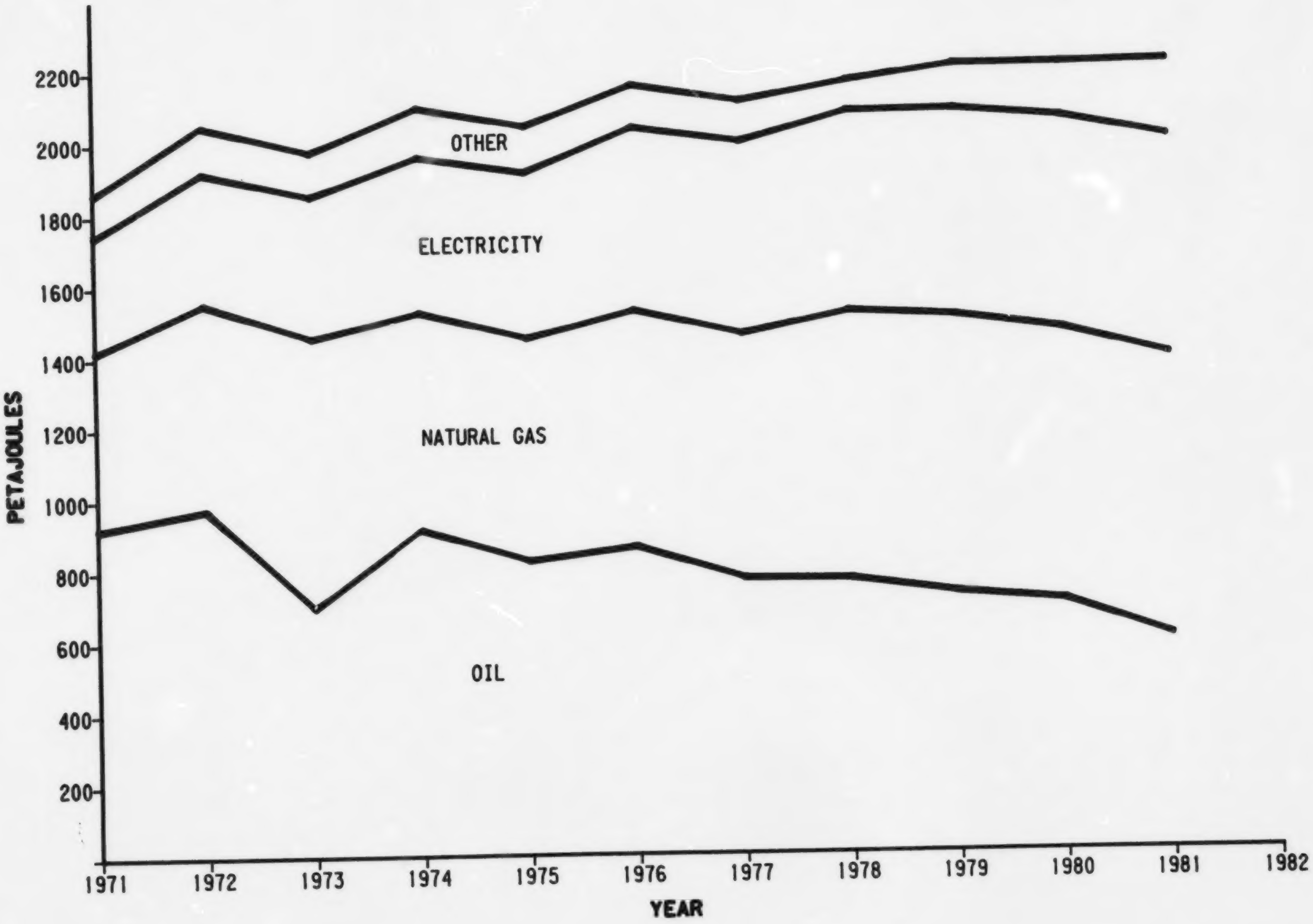

FIGURE 5-4
ANNUAL ENERGY COMSUMPTION IN CANADA
BY THE RESIDENTIAL AND
COMMERCIAL SECTORS

TABLE 5-2

Urban Residential Space Heating Market Share by Fuel Type - 1981
(Percent of Dwelling Units)

Province	Oil	Gas	Electric	Other
Newfoundland	56	-	38	6
Prince Edward Island	92	-	4	4
Nova Scotia	83	-	12	5
New Brunswick	71	-	24	5
Quebec	49	8	42	1
Ontario	28	54	17	1
Manitoba	8	70	21	1
Saskatchewan	2	90	7	1
Alberta	1	91	8	-
British Columbia	22	53	23	2
Canada	31	44	24	1

Source: Statistics Canada "Occupied Private Dwellings - Selected Characteristics" Catalogue #92-932

5.3 PRELIMINARY SELECTION OF REPRESENTATIVE DISTRICT HEATING SITES

531 GENERAL

As a preliminary step to developing the heat loads and heat densities of the "typical" Canadian city, which form the basis for the quantitative assessment of the potential of district heating, Canadian cities and towns were screened on the basis of the district heating parameters discussed in Part 5.2.

The 1981 census provides extensive information on populations, population densities, housing types and heating equipment for different regions in Canada. These data has been used to develop the estimated heat loads and heat densities of the cities that were chosen for analysis. Statistics Canada provides information for Census Metropolitan Areas (CMA) - areas with a total population greater than 100,000 - and Census Agglomerations (CA) - areas with a total population of 10,000 to 99,999 [237]. Each CMA and CA consists of one or more components (municipalities, cities). For example, the CMA of Toronto has a population of about three million people while the City of Toronto has a population of about 600,000. The difference is that the CMA of Toronto includes the City of Toronto plus many surrounding boroughs. Statistics Canada also provides simplified maps or census tracts of many of the CMA's and CA's. These provide information both on the border limits of each component (municipalities, cities, etc.) and whether the component consists of rural and urban areas.

Two criteria have been used in the process of selecting sites - population and population density. The minimum population density considered is 800 inhabitants per km^2. This criterion limits the number of large, low heat density areas to be included in the analysis. It is reasonable to assume that the average heat density below this limit is very low. For example, if there were an average of 2.5 inhabitants in each residential unit and each unit consumed 124 GJ per year, the heat density would be 40 MJ/m^2. This heat density is not sufficient to justify the installation of a district heating system. While there may be sub-areas within a low heat density area, such as a small concentration of commercial buildings with a heat density that would be of interest to district heating, experience indicates that such areas are normally relatively small and unlikely to affect the overall potential for district heating. In some cases, none of the components within a CMA or CA had a population density which exceeded the minimum. In several such instances, components that had more than 50,000 inhabitants but a population density just below 800 inhabitants per km^2 have been included.

The selection of sites was also based on a minimum population of 10,000. European experience indicates that the potential for district heating is substantially reduced below this population level.

These two criteria eliminate, for purposes of this study, approximately six million of 19 million Canadians living in urbanized areas at the time of the census. The classification of the various remaining Canadian communities that passed this initial screen has been carried out using three parameters: population, degree days and type of heating system.

532 POPULATION

As discussed in Part 5.2, heat density and connection density are related to population, therefore, population should give an indication of relative heat densities. High density housing and office buildings tend to represent a higher proportion of a city's total building stock in larger population centers and therefore classification by population will also reflect variations in building stock and consequently variations in heat and connection density. The three population classifications used in the study are:

- the three largest cities (Toronto, Montreal, Vancouver) with more than 900,000 inhabitants;
- 100,000 to 899,999 inhabitants; and
- 10,000 to 99,999 inhabitants.

The population classification of the largest cities (i.e. Toronto, Montreal and Vancouver) is based on the population of the CMA. The remaining cities have been classified according to the previously defined criterion.

533 DEGREE DAYS

Based on the assumption that heat consumption varies directly with degree days, classification of the CA's and CMA's based on degree days provides a convenient method of identifying those areas which, based on climatic factors, are likely to be high or low energy consuming areas. As shown in Figure 5.5 the bulk of Canadian cities experience annual degree days that vary between 3000°C and 6000°C. Therefore, the three following categories have been selected for this classification:

- annual degree days less than 4,000°C;
- annual degree days between 4,000 and 5,000°C; and
- annual degree days greater than 5,000°C.

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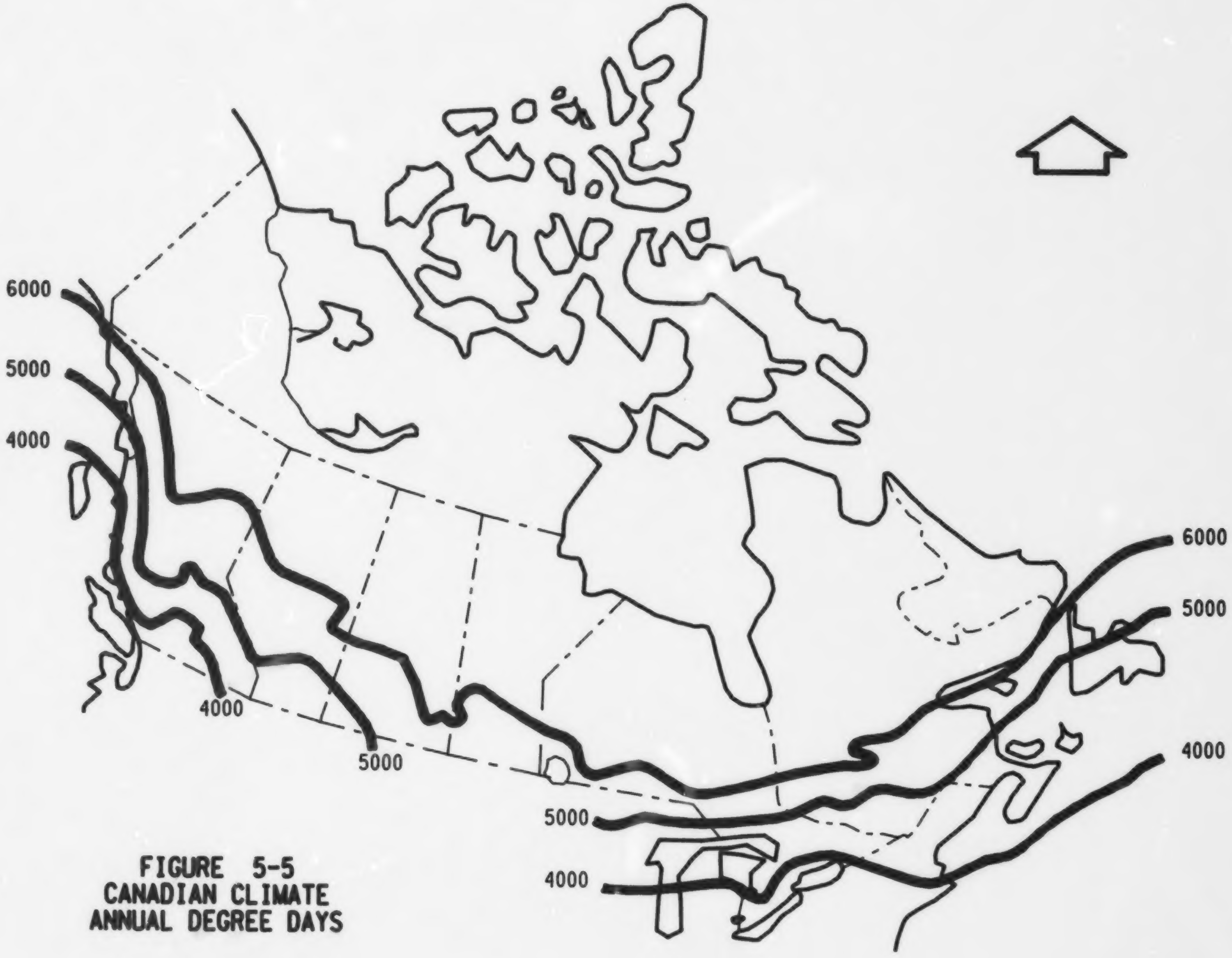

6000
5000
4000
4000
5000
5000
4000
6000
5000
4000

FIGURE 5-5
CANADIAN CLIMATE
ANNUAL DEGREE DAYS

Due to the high percentage of electrical heating in Quebec and because the retrofit costs are high for such systems, locations in Quebec have been classified separately. Newfoundland also has a high percentage of electrical heating, however, because only three Newfoundland communities have been considered they have not been classified separately.

The towns and cities that have been considered as potential district heating sites are classified as shown in Table 5-3. and are listed in order of decreasing population.

5.4 REPRESENTATIVE SITES

In order to evaluate which areas of Canadian cities have the most potential for district heating, a group of selected Canadian cities have been analyzed in order to develop a typical heat density "map". These "maps" provide a general configuration that could be applied to any Canadian city. In order that the analysis reflect the structure of the cities, differences resulting from climatic conditions have been normalized to a reference value of 4500°C annual degree days. The criteria for the selection of the representative communities were that to the extent possible:

- they represent a range of different sizes and geographical regions of Canada;
- that census tract information exist for each selected site;
- that district heating studies providing heat load data exist; and
- other pertinent information be available.

Table 5-3

Classification of Census Metropolitan Areas and Census Agglomerations

Population (000's)	Location	Annual Degree Days		
		<4000°C	4000-5000°C	>5000°C
900	Quebec		Montreal (2651)	
	Other	Vancouver (969)	Toronto (2811)	
100 - 899	Quebec		Hull (149)	Quebec City (478) Chicoutimi (110)
	Other	Hamilton (326) Windsor (212) Victoria (177) St. Catharines (124)	Ottawa (389) London (254) Kitchener (139) Halifax (115) St. John's (110) Oshawa (100)	Calgary (593) Winnipeg (564) Edmonton (549) Regina (162) Saskatoon (154) Thunder Bay (112) Sudbury (100)
10 - 99	Quebec		Sherbrooke (83) Drummondville (39) St. Hyacinthe (38) Trois Rivieres (32) Valleyfield (30) St. Jean (25) Sorel (23) Victoriaville (22)	Shawinigan (47) Rimouski (28) Sept-Iles (26) St. Jerome (25) Thetford Mines (20) Val d'Or (19) Riviere du Loup (13)
	Other	Brantford (72) Kamloops (55) Sarnia (51) Chatham (41) Port Albernia (20) Vernon (20) Leamington (13)	Kingston (75) Saint John (73) Guelph (71) Dartmouth (62) Peterborough (61) Lethbridge (54) Moncton (53) Sydney (51) Barrie (38) Belleville (35) Stratford (26) Corner Brook (24) Orillia (24) Brockville (20) Owen Sound (20) Sydney Mines (19) Charlottetown (17) Cobourg (16) Cranbrook (16) Prince Rupert (15) Trenton (15) Lindsay (14) Pembroke (14) Hawkesbury (10) New Glasgow (10)	Sault Ste. Marie (75) Red Deer (46) Moose Jaw (34) Thompson (14) Labrador City (12)

The cities that have been selected along with relevant general information are given in Table 5-4.

5.5 HEAT DENSITIES OF REPRESENTATIVE SITES

The capital cost of district heating, expressed in terms of the unit cost of energy, decreases rapidly with increasing heat density. Consequently, a heat density analysis is often used in the early stages of a DH study or in energy planning to evaluate which areas of a city are more suitable for DH and should be studied more closely.

In order to select and classify Canadian cities, it has been assumed that each city has a single high heat density core surrounded by an area that decreases in heat density as the distance from the core increases. This assumption is valid for cities such as Winnipeg and Saskatoon. However, in some areas (i.e. Halifax/Dartmouth, Ottawa/Hull) the CMA includes two built-up cores. In these cases, each city is classified separately. Toronto, Montreal and Vancouver are even more complex. They each have a well developed downtown core, but also have several outlying regions with their own built-up cores. For this study, these CMA's were treated as if they had a single core at the center of the main city.

In an attempt to quantify the heat densities in the different areas in most cities, five heat density zones within a typical city have been defined.

1. Core: High density commercial section.
2. Residential: The peripheral area consisting mainly of detached and semi-detached housing.

TABLE 5-4

Statistical and Climatic Data for Representative Sites

Site	Population	Annual Degree Days	Design Temperature	Temperature Difference
		(°C)	(°C)	(°C)
Edmonton	532,000	5,590	-32	50
Halifax	115,000	4,123	-16	34
Ottawa	295,000	4,674	-25	43
Saint John	81,000	4,771	-22	40
Saskatoon	154,000	6,077	-35	53
Toronto	599,000	4,082	-18	36
Victoria	64,000	3,075	- 5	23
Winnipeg	564,000	5,887	-33	51

Sources: The Supplement to the National Building Code of Canada - HRCC No. 17724 Statistics Canada, "Census Metropolitan Areas and Census Agglomerations with Components", Catalogue #95-903.

3.	Intermediate:	These areas generally lie between the core and the residential areas and consist mainly of residential units ranging from detached to high rise apartment buildings. Lots are generally small relative to the floor area. This area includes some commercial development such as offices, clinics and shopping centers.
4.	Industrial:	Most cities have some type of industrial development. Although some industrial loads may be attractive for district heating, the diverse and often unique characteristics of such loads make them impractical to consider in a study of this nature.
5.	Rural:	Small rural communities which surround most cities are not included in this study because the heat loads and heat densities are too low for district heating to be economically feasible.

The 1981 census provides housing types by individual census tracts. Some of the types of housing are categorized as follows [237]:

Single Detached:	A dwelling not attached to any other building and surrounded by open spaces.
Semi-detached:	One of two dwellings attached side by side but not attached to any other building.
Duplex:	One of two dwellings, one above the other, not attached to any other building.

Apartment (less than 5 stories)	Dwelling in a triplex, quadruplex or in a non-residential building or house that has been converted.
Apartment (more than 5 stories)	Dwelling unit in a high-rise apartment building.

To determine the heat densities of the three heat density zones to be considered in the representative sites, various techniques were used. For the residential zones, annual energy consumption for space heating and domestic hot water for various housing types was estimated based on the literature and discussion with persons involved in the energy sector. The annual consumption values used in the study at the reference climate of 4,500°C annual degree days are:

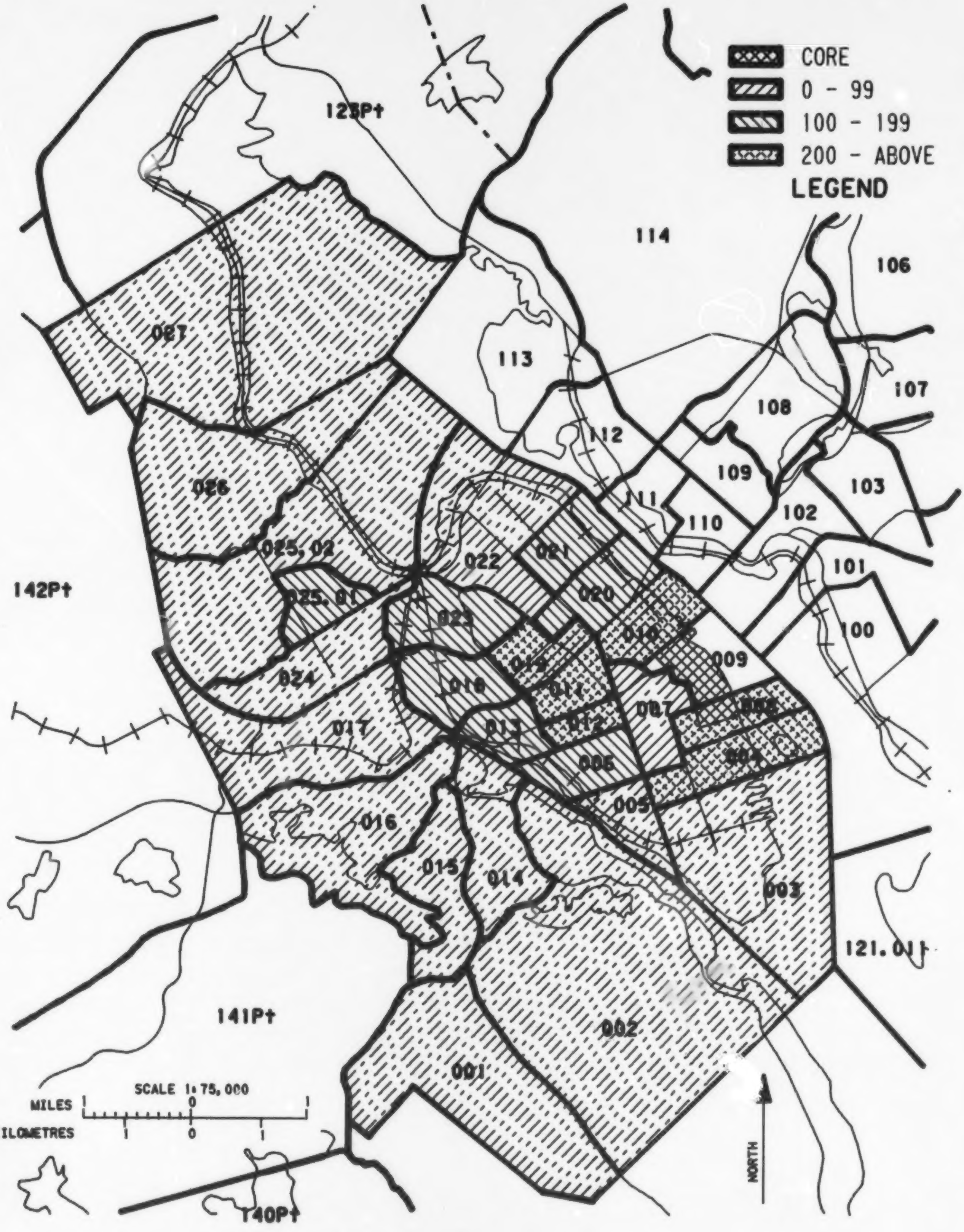
Single Detached House	130 GJ
Semi-Detached	97 GJ
Duplex	97 GJ
Apartments	56 GJ

Using these values, heat densities in residential zones have been estimated for each census tract area of the representative sites.

The heat densities of the core and the intermediate zones proved to be a more difficult problem. Where current district heating studies were available, they were used as the source of information on heating loads. Unfortunately, studies were available for only a few of the representative sites. In addition, the planning departments of each of the cities were contacted in order to determine the floor/area ratio (FAR) and the location of the core and intermediate areas. The response from the planning departments ranged from excellent to no response at all. Information was also obtained for a group of office buildings in Ottawa in order to determine a typical energy consumption figure for offices. This figure was set at 700 MJ/m^2 per year for the reference climate of 4,500°C annual degree days.

Identification of what should be considered as the intermediate areas of the cities presented some difficulty. In some cities, streets radiating out from the core were classed as intermediate zones and in others, a land area surrounding the core was identified as the intermediate zone. Where no intermediate area was specifically identified, ten percent was added to the energy consumption of the areas surrounding the core. This often had little effect on the heat density classification of the area. Where streets were identified as intermediate zones a linear heat density of 25 GJ/m was assumed and added to the residential heat load. This was based on the assumption that commercial establishments have a heat density of 500 MJ/m^2 and occupy lots on the street front (i.e. the front half of the block is commercial, the back half is residential). These lots were assumed to be 30 m in depth and built up to an FAR of one. The cross streets were presumed to occupy fifteen percent of the length of the street. Therefore, for each side of the street, the linear heat density was estimated as: $30 \text{ m} * 1 * 500 \text{ MJ/m}^2 * 0.85 = 12.75 \text{ GJ/m}$ or 25.5 GJ/m for both sides of the street. Again, this generally added about ten percent to the residential load.

Figure 5-6 is a heat density map of Halifax which shows the typical configuration of the representative sites [239]. Table 5-5 gives the results of the analyses that have been performed on the representative sites. It indicates that the cities vary greatly from one to the other with respect to heat load. There are however, some elements of consistency that do occur despite the differences in size and make-up of the cities.


CORE
0 - 99
100 - 199
200 - ABOVE
LEGEND
123Pt
114
106
113
107
108
112
109
103
111
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102
027
026
025.02
025.01
022
021
020
101
142Pt
023
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1
NORTH
140Pt

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FIGURE 5.6

HEAT DENSITY MAP OF HALIFAX

Table 5-5

Annual Heat Consumptions and Heat Densities for Selected Areas

	Edmonton		Winnipeg		Halifax		Saskatoon		Victoria		St. John		Ottawa		Toronto	
Population (1,000)*	532		564		115		154		177		81		389		599	
Heat Consumption (MJ/m^2)	(TJ)	(%)	(TJ)	(%)	(TJ)	(%)	(TJ)	(%)	(TJ)	(%)	(TJ)	(%)	(TJ)	(%)	(TJ)	(%)
Core	2050	10	1679	9	893	19	945	14	380	4	527	18	1807	12	6511	26
200 and above**	375	2	2609	11	1062	23	-	-	1799	19	109	4	3134	21	14163	56
100 - 199	8607	41	10830	47	973	20	2462	36	2508	27	543	18	4931	33	3561	14
0 - 99	9778	47	7772	33	1781	38	3357	50	4582	50	1780	60	5110	34	837	4
Total	20810	100	22890	100	4709	100	6764	100	9269	100	2959	100	14982	100	25072	100
Heat Consumption per Capita (GJ/inh)																
Total	39		41		41		44		52		37		39		42	
Core	4		3		8		6		2		7		5		11	
Heat Density (MJ/m^2)																
Core	1139		645		1050		1050		543		785		1181		1331	
200 and above**	217		246		252		-		288		419		283		301	
100 - 199	123		137		132		126		135		131		130		156	
0 - 99	43		15		35		35		42		6		46		43	

* this figure includes the population of the total area analyzed; therefore, in some cases it will be greater than the city population
** not including core area

Total residential energy consumption is based on figures from Statistics Canada and estimates of heat consumption per unit that appear to be reasonably accurate, and consequently these values are probably the most dependable. In each city, residential consumption represents a large proportion of total energy consumption so that the relative accuracy of these estimates will tend to have a positive influence on the accuracy of the overall results.

As Table 5-5 indicates, the energy consumption per capita based on city population is reasonably consistent, varying between 37 and 52 GJ per inhabitant per year. A number of different techniques were used to estimate the energy consumption in the downtown core. The most dependable results are probably for cities where heat loads were developed based on existing district heating studies. Edmonton and Winnipeg are two such cities with similar populations. Total energy consumption in the core area of these two cities varies by about 20 percent demonstrating that the size and characteristics of the downtown core can vary substantially between cities of the same size.

The relationship between the energy consumed in the core and the total energy consumed also varies to a large degree from city to city. Good information was available for both Victoria and Toronto and yet they provided the highest and lowest percentages. (Victoria, 4%; Toronto, 26%). The CMA of Toronto includes a large outlying area, and consequently it is reasonable that the downtown area will be very densely developed and thus have a high energy consumption. The remaining cities varied between 9 and 19 percent.

For the areas with a heat density of 200 MJ/m^2 or more, the heat consumed as a percentage of the total varies greatly from 0 percent in Saskatoon to 60 percent in Toronto. The same reasoning as put forth in the previous paragraph will again apply to Toronto. The heat density in these areas varies between 200 and 300 MJ/m^2 for each city except Toronto and Saint John. The information for Saint John was limited and therefore, the results for this city may be suspect; however, the total area and hence the energy consumption is small which makes any errors of less consequence.

For areas with a heat density below 200 MJ/m^2, the heat consumed accounts for at least 58 percent of total consumption in every city except Toronto. These areas can be assumed to be generally low-rise residential areas and cover large areas surrounding the cores. Because of its nature, Toronto has a very small portion of low density housing. The heat densities in these areas (i.e. 0 - 99 MJ/m^2 and 100 - 199 MJ/m^2) are basically defined by these limits; however, in both categories, the average consumption is below the median of the limits.

A full explanation of the large variations in heat load and heat density that appear to exist in these cities would require some method of confirming the accuracy of the estimated heat loads and also knowledge of the history, development and make-up of the cities, much of which is not available.

5.6 THE CANADIAN MODEL

An overall discussion of the potential for district heating in Canada has to be based on a description of the environment that exists for district heating. For this purpose, a simplified model of potential sites has been developed. This model is based on the results of the analysis of the heat loads of the representative sites and describes the total energy consumption and its distribution in different heat density areas. The model cannot claim to describe an "average" city in Canada, but it could be assumed that a large number of Canadian cities follow a pattern that is similar to the pattern outlined in the model.

It is not intended that the model be applied to any specific city, particularly considering the variability of results flowing from the analyses of the representative sites. The class of cities consisting of the cities of Toronto, Montreal and Vancouver has been modeled according to the results from Toronto. Cities with 100,000 to 899,999 inhabitants are modeled according to figures close to the average values for the cities analyzed excluding Toronto. Essentially, the same values have been used in the category of 10,000 - 99,999 inhabitants; however, based on earlier discussion, the heat density in the downtown area has been assumed to be somewhat less.

Table 5-6 provides estimates of the typical per capita heat consumption and the distribution of heat consumption and heat densities for the various population and climatic (annual degree days) categories set out in Table 5-3.

TABLE 5-6

Estimated Heat Load Characteristics of Typical Canadian Cities

Population	900,000			100,000 - 899,999			10,000 - 99,999		
Annual Degree Days (000's)	4	4 - 5	5	4	4 - 5	5	4	4 - 5	5
Total Heat Consumption (GJ per capita)	35	45		35	45	55	35	45	55
Distribution of Total Heat Consumption by Heat Density (per cent)									
Core		25			10			10	
200 - and above*		60			10			10	
100 - 199 MJ/m^2		12			30			30	
0 - 99 MJ/m^2		3			50			50	
		100			100			100	
Heat Densities (MJ/m^2)									
Core	1170	1500		780	1000	1220	580	750	920
200 - and above*	270	350		170	220	270	170	220	270
100 - 199	115	150		100	130	160	100	130	160
0 - 99	40	50		25	30	35	25	30	35

* - excluding core area

PART 6

ENERGY SUPPLY SYSTEMS

PART 6 - ENERGY SUPPLY SYSTEMS

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6.1 GENERAL

This part of the report deals with the technological options and performance characteristics of systems which supply heat to the transmission and distribution networks of district heating installations.

Transmission and distribution systems are composed of supply and return piping. The heating medium, water or steam, is injected into supply piping of the network by the heating station at a specified temperature. This fluid circulates in the network providing heat to user installations and returns to the heating station at a reduced temperature.

It is the job of the heating plant to raise the temperature of the returning fluid once more to the specified supply temperature and pump it back into the supply piping of the DH network.

The quantity of heat to be supplied varies with user demand, and user demand is generally dictated by weather conditions. Cold weather generates higher demand, and heating stations then burn more fuel and supply greater quantities of heat to their networks.

The quantity of heat supplied is controlled by two variables: 'flow' and 'supply temperature'. Both parameters are varied to arrive at an optimum combination for supplying the heat demand under prevailing conditions. Changes in supply system flows and temperatures also change return system conditions and the station is designed to be responsive to these supply-return parameters and to inject the correct 'quantity of heat' into the network so as optimally to satisfy consumer demand.

Whether a DH network is supplied with heat by one central heating plant or by a number of heating plants will often depend upon its growth pattern.. For example, the first phase of a DH network may be quite small, and the network may grow in stages instead of growing to its full potential in one giant stride. In such a case either the first central heating plant may itself be increased in size to cater to growing demand, or new heat supply stations may be installed at favourable locations in the network. Also, if a second phase is much larger in size than the first phase, then the second heating station may operate as a base load plant and peaking duty be assigned to the smaller first plant.

The design of heating plants is based upon three major factors:

- The heat demands of the networks which they serve;
- Available heat sources, fuels, or thermal resource options; and
- The economics of, and potential market for, combined heat and power generation (termed CHP or Cogeneration).

These three factors are briefly discussed below:

- The seasonal heat demand and consumption of the network, the flow and temperature envelopes, the characteristics of the heating medium and the requirements for optimal control of heat supply are the basic data which emerge from the heat demand and consumption study and from the network design. A Load Duration Curve is then developed and the demand, if any, for cogeneration of electrical power is determined.

- In parallel with developing the load duration curve, an investigation is made of the local fuel and heat resource options. Ideally, low-grade fuels and heat resources (i.e. other than high-grade hydrocarbons such as oil and natural gas) should be used for district heating. Wood, peat, coal, municipal solid waste, and other low grade heat resources are often locally available and their use for district heating should be explored. Whereas individual house heating appliances are, in the main, restricted to using higher grade fuels and energy resources, DH stations can be designed to use a variety of low grade fuels and energy resources.

- The potential for cogeneration and sale of electrical power should be investigated at the same time and, if there is a market or a contiguous potential consumer for electrical power, then the station may be designed as a CHP (Cogeneration) plant instead of as a 'heating only' plant.

Now having briefly discussed the role, function and basis of design of heating plants, it is appropriate to review some of their characteristics and the equipment and system options of which they may be composed.

611 FIXED AND MOBILE PLANTS

Heating and cogeneration plants may be designed in fixed locations or be mobile for more flexible response to system change or growth.

The early stage of a DH system may be quite small. Both the time-scale and configuration of network growth may be uncertain at the time of planning the first phase. Such cases often do not warrant the high front-end cost of large, fixed central heating plants. On the other hand, small fixed plants do not benefit from economies of scale, cannot be moved when growth changes the load centre, and often do not have either space to grow or adequate cooling systems for expansion of capacity.

The drawbacks of starting the system with small units can be somewhat offset, however, since when network growth is established enough to warrant a fixed central plant, the latter can take the system base load and the small flexible plants can continue to operate, serving peak loads. The fully developed system can be so designed that it accommodates the capacities, performance, and subsequent replacement of the small units at the end of their somewhat shorter life-spans.

612 HEATING ONLY AND COGENERATION PLANTS

Central plants serving DH systems may either be designed as heating only plants or as cogeneration plants, which produce both heat and electrical power. Cogeneration plants may use a variety of equipment and systems, as described in detail in Part 6.3, to optimize the economics of their combined heat and power (CHP) generation to match load, system and seasonal demand characteristics.

The letters CHP are internationally recognized to mean combined heat and power, which is synonymous with cogeneration.

TABLE 6-1

Typical Figures Comparing CHP with Electrical Power Generation

	Efficiency of Electrical Power Generation %	Efficiency of CHP (Cogeneration) %
Energy in Fuel	100	100
Energy from Heat of Combustion (in boiler)	85	85
Energy in Electrical Power Produced	35	30
Energy in Useful Heat Produced	NIL(1)	40
Energy Wasted	65	30
Overall Efficiency	35	70

(1) When only electrical power is generated all this heat, which could be usefully applied, is wasted, mainly because the remote locations of most large power stations place them out of range of major population and industrial centres in terms of distance for economical transport of heat. Since electricity can be more economically transported over long distances than heat, only electrical power is generated at remote stations. (In this context remote means anything more than 30-40 km, beyond which it becomes uneconomic to transport heat.)

It can be seen that the efficiency of fuel utilization in the CHP or cogeneration mode is twice its efficiency in electrical power generation alone.

Cogeneration can sometimes solve localized problems in Canada. In instances where electrical utilities find it difficult or exorbitantly expensive to set up long distance transmission facilities, they are prospective purchasers of locally cogenerated electrical power, since they already have established distribution facilities. In such cases electrical utilities welcome the supply of power from privately owned CHP systems.

613 SYSTEM AND FUEL/ENERGY RESOURCE OPTIONS

Central heating plants serving DH networks can be designed to use a wide variety of equipment and system combinations based on the fuel or energy resource options which are locally favourable.

Part 6.2, which discusses fuel and energy resource options in detail, makes a distinction between high grade and low grade fuels and other low grade energy resources. Natural gas and oil (and its derivatives such as gasoline, kerosene and light/diesel fuel oils) are considered high grade fuels. These fuels have a high energy density which, apart from their excellent flow characteristics, contributes largely to their economic transportability. These fuels also have the best combustion characteristics, the least pollution potential, and no ash disposal problems. However, they also happen to be the fuels which are limited in terms of global resources, the most desirable fuels for transportation and the feedstocks for a host of essential chemicals and fertilizers. There is general concensus in favour of replacing high grade with low grade fuels for use in space and domestic water heating and space cooling.

Electricity is considered a high grade energy resource (also termed a currency) which can be generated by burning either high grade or, preferably, low grade fuels. It is a most versatile resource over which excellent control can be exercised when it is applied to power drivers, heating, cooling or instrumentation and control.

The easiest and most economical route, if resources are limitless, is to use high grade fuels for district heating. However, resources of high grade fuels are limited and therefore the use of low grade fuels and energy resources must be the preferred options for district heating.

Part 6.2 contains a detailed discussion on low grade fuels and energy resources and it will, therefore, suffice here to discuss them generally.

A major characteristic which differentiates low grade from high grade energy resources is the economics of transportation arising from their respective energy densities, i.e. the amount of energy (measured in joules) contained in each unit weight (measured in grams) of the resource. Since the joule (J) and gram (g) are small units, the energy density is usually stated in kilojoules (kJ), megajoules (MJ), or gigajoules (GJ) per kilogram (kg).

Transportation cost being generally proportional to the weight of the material transported, a low energy density fuel like wood, containing 10 MJ per kilogram of material, will likely cost much more to transport than oil, which contains 40 MJ per kilogram of material. A compounding factor is that hogged or chipped wood fuel also has a lower bulk density, i.e. it occupies more volume per kilogram of weight (and therefore per MJ of energy) than oil. This factor further increases its cost of transportation. It also does not flow, and cannot therefore be piped like oil.

The combined effect of these factors is that most low grade fuels can only be used locally, close to where they are generated, whereas natural gas and oil can be transported transcontinentally and globally.

A great deal of R&D work is under way investigating the technology and economics of converting low grade energy resources into high grade, economically transportable, liquid and gaseous fuels. One barrier to success in this direction is that low grade resources are seldom available in large enough quantities within a small enough area to permit conversion and product transportation facilities, on an economic scale, to be sited in one place.

It is generally the case that small quantities of low grade energy resources are locally available in a number of places, either within, or within economic transportation distance from, centres of population and industry.

Examples of such low grade resources are:

- fuel wood;
- fuel peat;
- municipal and industrial solid combustible wastes, known as MSW (including waste from wood working, paper and rubber industries);
- low grade coals, including lignites;
- low grade liquid and gaseous effluents from municipal, industrial and utility sources;
- geothermal energy;
- petroleum cokes, pitches, oil shales;
- wind energy;
- solar energy;
- ocean thermal and wave energy.

As explained above, all low grade resources may be classified as local opportunity resources deserving exploitation by any community which intends to review the feasibility of district heating for its inhabitants.

614 TRANSPORTATION TO, AND STORAGE OF, LOW GRADE FUELS AT CENTRAL HEATING STATIONS AND DISPOSAL OF ASH

When a central heating plant is located within a community, fuel must be transported to it either from outside (if wood or coal) or from within the populated zones (if MSW or industrial waste).

Assuming a truck size of 25 m^3 payload capacity, each truck load would transport a quantity of fuel heating energy based upon the energy density (MJ/kg) and bulk density (kg/m^3) of the selected fuel.

For the four central heating plant sizes (18 MWt/150 MWt/ 300 MWt/1500 MWt), which have been cost estimated in Part 6.4, Tables 6-2 and 6-3 show the order of magnitude of populations which would be served by those sizes of stations and the numbers of trucks per day required to transport four selected fuels to the heating stations.

Figures in Table 6-3 indicate that the locations of large central heating plants, using low grade fuels, should be so selected that local inhabitants do not experience traffic congestion or noise, odour and dust pollution caused by the fuel trucks.

TABLE 6-2

Energy Transported per Truckload of 25 m^3 Payload for Four Selected Low Grade Fuels

Fuel Type	Energy Density MJ/kg	Wt. Bulk Density kg/m^3	Energy Bulk Density GJ/m^3	Energy Transported GJ/Truckload
Wood	10	300	3	75
Coal	28	800	22.4	560
Peat	11	350	4.32	96
MSW	11	300	3.3	83

TABLE 6-3

Order of Magnitude Estimates of Populations Served and Fuel Transportation Required for Four Sizes of District Heating Stations Using Four Selected Low Grade Fuels

Station Size	Population Served @ 45GJ per annum per Inhabitant	Fuel Type	Maximum Fuel Consumption GJ/Day	Energy Transported GJ/Truck	Traffic (No. of Trucks/Day)
18 MWt	4,500	Wood	2393	75	32
		Coal	2287	560	4
		Peat	2393	96	25
		MSW	2393	83	29
150 MWt	37,510	Wood	16405	75	219
		Coal	15428	560	28
		Peat	16405	96	171
		MSW	18514	83	223
300 MWt	75,030	Wood	32808	75	438
		Coal	30864	560	55
		Peat	34560	96	360
		MSW	37032	83	446
1500 MWt	375,250	Wood	164088	75	2188
		Coal	154320	560	276
		Peat	172848	96	1801
		MSW	185184	83	2231

Storage of low grade fuels at central heating stations requires care and good planning primarily for the following reasons:

- Vast areas of storage space are required due to the low energy and bulk densities of the fuels.

- Due to their flammable nature, the fuels are a hazardous storage material. Milled peat, for example, is subject to spontaneous combustion and only a small emergency storage (about 7 days) is permitted at a station site.

- Dust and odour arising from the stockpiles constitute a potential pollution hazard to the locality.

- In the case of MSW, a back-up sanitary landfill site is a regulatory requirement in some cities to cater for both planned and emergency station outages. Besides this, sanitary landfill for disposal of ash resulting from incineration of MSW is required within an economical transportation distance from the station.

615 POLLUTION POTENTIAL OF LOW GRADE FUELS AND ENERGY RESOURCES

This subject has been dealt with in detail in another part of the report. It is sufficient to say here that almost every low grade energy resource needs to be carefully reviewed in terms of its pollution potential. As a general rule, the lower the grade of resource, the greater the pollution hazard. But, as usual, many exceptions can be cited to this generalization.

Despite the many problems posed in the utilization of low grade resources, there is no doubt that such local energy resources as MSW, wood waste, other industrial wastes, and low temperature municipal/industrial/utility discharges afford communities valuable opportunities for application of otherwise waste energy to community heating projects. Such opportunities should be eagerly seized and exploited, or at the very least, reviewed for their potential, perhaps in combination with, or hybrid utilization of, other energy resources.

Municipal solid waste, for example, is generated by every community. Sanitary landfill takes up valuable space and creates pollution problems for ambient air and water contiguous with the landfill site. Using MSW as an energy resource can be a simultaneous solution to the problems of pollution, space and domestic water heating.

Remote Canadian communities often face very high fuel costs, because high grade fuels, such as heating oil and propane, often have to be flown in to them. Economical and reliable methods of utilizing low grade local fuels, such as wood and peat, would make these communities independent of imported fuels and also provide local employment. Cogeneration systems in such locations, which major grids may not serve, would provide electrical power along with space and water heating, and the fuel could be utilized at its optimum efficiency in the CHP mode.

617 ECONOMIES OF SCALE AND COSTS OF HEATING PLANTS VS. COGENERATION PLANTS - PHASING OF DH SYSTEMS

Parts 6.3 and 6.4 deal with specific cases where cost estimates have been developed for heating plants and cogeneration plants.

As a general rule, larger plants are more economical in terms of front-end investment dollars per kilowatt installed. However, it is often difficult to raise all the money required for a large district heating system at one time. In fact, it is seldom possible to install a very large district heating system in one phase. The development is more likely to be phased in several steps. This leads to higher dollars per kilowatt installed cost, but to lower front-end capital demand. Also, where district heating is being proposed for the first time, it gives the potential users of the system time to get used to and accept the idea, when it is introduced as a phased development.

618 COMBINED DISTRICT HEATING AND COOLING

By the use of absorption chillers, the heat energy, provided by the central station to the distribution network, can also be converted to cooling energy in the summer months. Alternatively, the electricity generated by a CHP plant can be used to drive air conditioners in the summer.

Where cooling loads are also available, district heating systems can operate at a higher annual average load factor, thus enhancing their economic viability. In certain areas of the United States, where there is a reasonable balance between winter heating and summer cooling loads, district heating/cooling systems can operate at almost full load all year round.

6.2 FUEL AND ENERGY RESOURCE OPTIONS

621 CONVENTIONAL OPTIONS

The conventional fuel and energy resource options for district heating are:

High-Grade Options

- Fuel Oil
- Natural Gas
- Electricity

Low-Grade Options

- Coal
- Wood/Biomass
- Peat
- Municipal Solid Waste (MSW)

District heating central stations fuelled by these options are described, analyzed and cost-estimated in Parts 6.3 and 6.4 of this report.

High grade fuels are defined as those which have the following advantages:

- high energy density (MJ/kg) for solid fuels and (MJ/m^3) for gaseous fuels;
- low moisture content;
- low ash content. This eliminates the problems of ash collection and disposal for the householder;
- high bulk density. This favours economy and ease of transportation by truck and/or pipeline;
- ease of combustion control;
- high combustion efficiency in small furnaces;
- low or negligible contents of sulphur, heavy metals, and other contaminants which could cause unacceptable local pollution levels or erosion/corrosion in the heat recovery system.

High grade fuels or energy currencies generally used in building heating in North America are natural gas and light fuel oils, and electricity.

When gas and oil are burned in small furnaces a major proportion of their chemical energy, in the form of heat (ranging 55% to 95%), is recovered and applied to space or domestic water heating. The new generation of high efficiency gas furnaces, which can operate at efficiencies up to 95% are, however, significantly more expensive than conventional furnaces which operate at efficiencies ranging from 55% to 75%. The unrecovered heat content of the fuel escapes up the chimney in the products of combustion which constitute the flue gases.

One aspect of fuel combustion in small furnaces which is not well understood is the difference between:

- design efficiency;
- steady state efficiency; and
- seasonal/annual efficiency.

These may be defined as follows:

.1 Design Efficiency

This is the efficiency at which a furnace operates when new and tested in a laboratory under optimum conditions. At the time of such testing the burner is in perfect condition and the heat transfer surfaces are clean. This is therefore termed the design efficiency, and is the highest the furnace can attain. It may be compared to Transport Canada fuel consumption ratings for automobiles. They are ratings which may not be achieved under actual driving conditions.

.2 Steady-State Efficiency

This is the efficiency which a furnace in regular use achieves some minutes after start-up when it has attained its steady operating temperature. If the heat lost by a building exactly equals the heat which the furnace provides under its steady state operation, then the furnace would continue to operate at its steady state efficiency as long as this equation is maintained. However, this seldom occurs. In practice most furnaces are designed for the worst ambient conditions which the building is likely to encounter plus a reasonable safety margin. The result of this is that most building furnaces operate in an 'on-off' mode, generally more 'off' than 'on' on a seasonal basis, since they have considerable excess capacity.

Continuous steady-state operation may be likened to a car running steadily at its optimum speed on a highway on a clear, mild, calm day, and on a level, well-surfaced road. Since the efficiency of the machine under such conditions would be close to, but may not equal, design efficiency, the gas consumption of the car would be close to, but may not equal, Transport Canada ratings.

.3 Seasonal Efficiency

This is the overall-average efficiency which a furnace achieves through a 12-month period encompassing all the seasons of the year. It includes the lower efficiencies encountered during starting and stopping and the 'off-cycle' losses. Again this may be likened to the overall-average gas consumption of a car through an annual driving period, combining city and highway driving in average proportions and taking account of seasonal factors (for example, it is well known that the gas consumption of all cars is significantly higher during the winter months).

The following table gives indicative figures for household furnace efficiencies. It must be understood that these are not absolute figures, but rather those which are generally recognized as being reasonably close to actual efficiencies encountered in testing and in practice.

TABLE 6-4

Comparative Indicative Household, Apartment and Office Furnace Efficiencies

FURNACE TYPE	DESIGN EFFICIENCY %	STEADY-STATE EFFICIENCY %	SEASONAL EFFICIENCY %
Using Primary Energy			
Conventional Oil Fired	80	75	60-65
Conventional Gas Fired	75	70	55-65
High Efficiency Gas Fired	85	83	70-75
Condensing Gas Fired	95	92	80-90
Using Secondary Energy			
Electrical Resistance Heating	100 (3)	100 (3)	100 (3)
Electrical Heat Pumps	Design COP(1) Based on seasonal ambient-temp. variations	About 5% less than design COP	123(2)

(1) COP - Coefficent of Performance.

(2) As computed for a particular case, using an example of a residential home in Toronto with a 31,650 kJ/h heat loss at design temperature and applying a 5°F bin method for determining total annual building load.

(3) This figure indicates that electricity used for heating within a building functions at 100% efficiency, so that all the electricity is turned into end-use heat. But it must be remembered that electricity itself is secondary energy which is generated by the combustion of primary fuels, and that the operation of converting primary fuels into electrical (secondary) energy is conducted at efficiencies ranging typically 17% to 35%. Thus only 17% to 35% of the primary energy in the fuel is converted to heat in the home, the

As the table indicates, there is a considerable spread in operating efficiencies, and most home furnaces operate at annual average seasonal efficiencies of 55% to 65% using high grade, expensive, fuels.

Canadian prices of these high grade fuels have remained, and still are, below world prices. This insulates Canadians against the full economic penalty of using high (transportation) grade fuels for space and domestic water heating; a purpose which low grade fuels could serve equally well.

The following table computes the "fuel-cost" of a gigajoule (GJ) of heat provided into a home in Central Canada, at the specified seasonal efficiencies and fuel costs of the most common types of home heating appliances.

TABLE 6-5

Comparison of Adjusted Fuel-Costs of Heat from High Grade Home Heating Fuels in Central Canada

Fuel/ Energy Currency	Type of Furnace/ Heating	Cost of Fuel		Effect of Seasonal Efficiency on Price (2)	Adjusted Fuel-Cost of Heat(3)
		Nominal Price(1)	Equivalent Price		
L. Fuel Oil	Conventional	31.46¢/L (39.3 MJ/L)	$8.01/GJ	$\frac{\$8.01/\text{GJ}}{0.60}$	$13.35/GJ
N. Gas	Conventional	$6.25/GJ (37.63 MJ/$m^3$)	$6.25/GJ	$\frac{\$6.25/\text{GJ}}{0.60}$	$10.42/GJ
N. Gas	High Efficiency	$6.25/GJ	$6.25/GJ	$\frac{\$6.25/\text{GJ}}{0.75}$	$8.33/GJ
N. Gas	Condensing	$6.25/GJ	$6.25/GJ	$\frac{\$6.25/\text{GJ}}{0.85}$	$7.35/GJ
Electricity	Resistance Heating	4.18¢/kWh (3.6 MJ/kWh)	$11.61/GJ	$\frac{\$11.61/\text{GJ}}{1.00}$	$11.61/GJ
Electricity	Heat Pump	4.18¢/kWh	$11.61/GJ	$\frac{\$11.61/\text{GJ}}{1.23}$	$9.44/GJ

(1) These prices have been used in the study as representing the average nominal prices of these fuels/energy currencies in Central Canada (taken from Table 6-6).

(2) The figures of efficiency are taken from the Table 6-4.

(3) It should be noted that the "fuel-cost" of heat does not include other costs related to heat production such as capital charges and the non-fuel costs of operation and maintenance.

The purpose of the above tabulation is to illustrate the discussion. A similar calculation may, if desired, be made by the reader for Atlantic and Western Canada by applying the nominal 1984 prices for light-fuel oil, natural gas and electrical power from Table 6-6 below.

TABLE 6-6

Nominal 1984 Prices for High Grade Domestic Fuels and Electricity

Fuels/ Electricity	Consumer	Region Atlantic Canada(1)	 Central Canada	 Western Canada
Light Fuel Oil	Residential	33.80¢/L	31.46¢/L	33.66¢/L
	Commercial	33.80¢/L	31.46¢/L	33.66¢/L
Natural Gas	Residential	$7.40/GJ	$6.25/GJ	$4.95/GJ
	Commercial	$8.51/GJ	$4.94/GJ	$4.45/GJ
Electrical Power	Residential	5.28¢/kWh	4.18¢/kWh	4.31¢/kWh
	Commercial	6.75¢/kWh	4.77¢/kWh	4.32¢/kWh

(1) Assumes availability of natural gas from the Venture Gas Field.

Any discussion of fuel options for heating must take account of three main factors:

- large-scale as opposed to small-scale combustion. This factor affects the efficiency of combustion and heat recovery;
- suitability of high-grade fuels for other essential requirements, such as for transportation and use as chemical feedstock, which cannot at present be served by low-grade fuels;
- cost and availability of fuels.

The foregoing has dealt with the small-scale combustion of high-grade fuels as practiced in residential and commercial establishments, and examined how the seasonal efficiency of combustion affects the resultant "fuel-cost" of the recovered heat.

The "fuel-cost" of residential and commercial heating amounts to 80% or more of the total cost of heating. The remaining cost arises from capital and non-fuel operating and maintenance (O&M) costs. Since the fuel related cost is so significant, the penalty for operating at low efficiency is proportionately high. For this reason it is important to examine the difference in the fuel-related cost of heating between small-scale and large-scale combustion of fuels.

Generally large heating stations operate more efficiently and with greater reliability than small residential and commercial heating furnaces. They can also be designed to use low-grade fuels.

The reasons for higher operating efficiencies and reliability of a large heating station are:

- The stations are generally composed of multiple units (base load and peaking units) so that, depending upon the load at any given time, individual units can be started up or shut down to follow load variations. As a result, those units which are operational run continuously, modulating within a reasonable load range, so that they operate at higher efficiencies than small 'on-off' mode residential and commercial furnaces.

- A large heating station serves hundreds of consumers whose demands do not all peak at the same time. Hence the total station capacity can be based on a 'diversity factor' of the order of 80% of the total combined peak demand of all its connected consumers. This enables the individual units of the station to operate more continuously and at a high unit load factor. Compared with this, as has been described earlier, small residential and commercial furnaces are designed to have a large over-capacity in order for each individual furnace to meet the highest possible demand of its own establishment. Thus, when a whole community is served by individual furnaces, the total "installed capacity" is generally between 200% and 300% of the combined design heat load of the buildings. For this reason a central heating plant is more cost effective.

- Central heating stations, unlike individually owned furnaces, are always designed to have adequate standby capacity. This may take the form of 2 x 100% units, 4 x 33.33% units or 3 x 50% units, thus providing at least one spare unit of sufficient capacity to provide 100% "firm" capacity to meet planned or forced outages. Such planning leads to a high degree of reliability when the station is operated and maintained by trained and qualified staff.

- It is necessary to re-emphasize that central heating plants can operate reliably even when using low-grade, inexpensive fuels, whereas individual small furnaces can operate reliably only when using high-grade, expensive fuels.

The points made above have dealt with 'efficiency', 'reliability' and 'capacity' of central heating stations as compared with individual furnaces.

The fuel-related costs of central stations using both high-grade and low-grade fuels will now be discussed.

For purposes of uniformity, this study has used the following bulk prices for fuels and energy supplied to central heating stations, dividing Canada into three price regions in order to hold the numbers of variables to manageable proportions.

TABLE 6-7

1984 Bulk Prices of Fuels/Energy Supplied to Central Heating Stations in Canadian Regions

Fuel/Energy	Units	Region Atlantic (5)	 Central	 Western
Natural Gas (5)	$/GJ	3.804	4.280	3.550
Fuel Oil	¢/L	21.740	16.100	14.970
Coal (1)	$/GJ	2.050	2.050	2.050
Wood/Biomass (2)	$/GJ	2.600	2.600	2.600
Peat (3)	$/GJ	2.000	2.000	2.000
MSW (4)	$/GJ	(0.960)	(0.960)	(0.960)
Electricity	¢/kWh	4.200	2.560	2.470

(1) A uniform price for coal has been used across the country because all heating station design and cost analyses carried out in Parts 6.3 and 6.4 of this report are based on a standard bituminous coal. Due to the significant impact of coal quality on thermal plant capital and O&M costs, it was not found possible, within the scope of this study, to develop capital and O&M costs for more than one quality of coal. It is recognized that the use of high sulphur, high ash coals results in high capital and O&M costs due not only to their lower quality in terms of heating value and ash, but also to the high costs of pollution abatement which their use imposes on the station.

(2) Whereas biomass generally includes such materials as straw, wood, industry wastes, bagasse, etc. the price used uniformly in this report applies to hogged wood fuel delivered to station site with an average moisture content of 40%.

(3) The price assumed here is for an average milled peat at an average of 50% moisture content as fired in conventional peat-fuelled thermal plants in Ireland, Finland and USSR.

(4) Municipal Solid Waste (MSW) has been assumed to be available at a negative energy cost due to a tipping fee charged by the heating station. The actual value of tipping fee will vary according to the cost of alternative means of refuse disposal.

(5) Assumes availability of natural gas from the Venture Gas Field.

Comparing the prices in Table 6-5 with those in Table 6-7 it is evident that, even with regard to high-grade fuels and energy such as natural gas, oil and electricity, the bulk use of fuels by central heating stations is economically advantageous.

We shall now discuss the efficiency with which central heating stations can use high-grade and low-grade fuels or energy, and compare efficiency adjusted fuel-costs of central stations with those of individual furnaces.

Various heating and cogeneration station capacities and unit configurations have been analyzed in detail in Part 6.4 of this report, using the following conventional fuels:

- Natural Gas
- Oil
- Coal
- Wood, Biomass
- Peat
- MSW

For each of these fuels both heating only and cogeneration stations are developed with the following four heat production capacities:

- 18 MW thermal output
- 150 MW thermal output
- 300 MW thermal output
- 1500 MW thermal output

The stations are so designed that the thermal (heat) production will be fed to a DH network and, in the case of CHP stations, the electrical production, in excess of station requirements, will be fed to a utility grid or industrial complex. It has been assumed that the CHP stations will respond primarily to heating demand and will provide electrical power to the grid as available after the heat demand is satisfied.

For all CHP stations it is assumed (conservatively) that extraction rather than back-pressure turbines will be used. Extraction systems are more expensive, but have the advantage that they can operate in a manner which provides a flexible relationship between heat and electrical power production.

The unit configurations and station capacities of the stations analyzed are as shown in Table 6-8 below:

TABLE 6-8

Capacities and Unit Configurations of Heating and Cogeneration (CHP) Stations Which are Analyzed in Part 6.4 of this Report

Heat Production Capacity of Station	Unit Configuration of Heating only Stations	Unit Configuration of Cogeneration Stations
18 MW_t	4 x 6 MW_t	4 x [3 MW_t Boiler & Cogen T-G Base Load Set + 3 MW_t Peaking Boiler]
150 MW_t	4 x 50 MW_t	4 x [25 MW_t Boiler & Cogen T-G Base Load Set + 25 MW_t Peaking Boiler]
300 MW_t	4 x 100 MW_t	4 x [50 MW_t Boiler & Cogen T-G Base Load Set + 50 MW_t Peaking Boiler]
1500 MW_t	4 x 500 MW_t	4 x [250 MW_t Boiler & Cogen T-G Base Load Set + 250 MW_t Peaking Boiler]

Note: "T-G" means "Turbine-Generator"

In the discussion which follows, it is proposed to compare the DH fuel options with individual building heating options based on a review of fuel use and efficiency of heating stations only, omitting discussion of cogeneration stations in this context.

The fuel price information in Table 6-9 below is taken from Table 6-7, and the annual operating efficiency is computed from the Annual Heat Production and the Annual Fuel Consumption figures in Table 6-11. Using this data Table 6-9 computes efficiency adjusted fuel related costs for the heat produced by central heating stations.

Fuel prices in Central Canada, taken from Table 6-7, have been used in Table 6-9 in order to permit comparison with the results of Table 6-5.

TABLE 6-9

Fuel Related Costs of Heat Production from Central Heating Stations

Station Heat Production Capacity	Fuel	Fuel Price in Central Canada	Annual Operating Efficiency	Effect of Efficiency on Price	Adjusted "Fuel-Cost" of Heat
18 MW_t	Gas	$4.28/GJ	78.99%	$\frac{\$4.28/\mathrm{GJ}}{0.7899\mathrm{x}0.95}$	$5.704/GJ
	Oil	16.10¢/L (41.81 MJ/L)	82.00%	$\frac{\$3.85/\mathrm{GJ}}{0.82\mathrm{x}0.95}$	$4.942/GJ
	Coal	$2.05/GJ	75.90%	$\frac{\$2.05/\mathrm{GJ}}{0.759\mathrm{x}0.95}$	$2.843/GJ
	Wood	$2.60/GJ	65.02%	$\frac{\$2.60/\mathrm{GJ}}{0.6502\mathrm{x}0.95}$	$4.209/GJ
	Peat	$2.00/GJ	65.02%	$\frac{\$2.00/\mathrm{GJ}}{0.6502\mathrm{x}0.95}$	$3.238/GJ
	MSW	($0.96/GJ)	65.02%	$\frac{\$0.96/\mathrm{GJ}}{0.6502\mathrm{x}0.95}$	($1.554/GJ)
150 MW_t	Gas	$4.28/GJ	84.01%	$\frac{\$4.28/\mathrm{GJ}}{0.8401\mathrm{x}0.95}$	$5.363/GJ
	Oil	16.10¢/L (41.81 MJ/L)	88.00%	$\frac{\$3.85/\mathrm{GJ}}{0.88\mathrm{x}0.95}$	$4.605/GJ
	Coal	$2.05/GJ	84.01%	$\frac{\$2.05/\mathrm{GJ}}{0.8401\mathrm{x}0.95}$	$2.569/GJ
	Wood	$2.60/GJ	79.00%	$\frac{\$2.60/\mathrm{GJ}}{0.79\mathrm{x}0.95}$	$3.464/GJ
	Peat	$2.00/GJ	75.00%	$\frac{\$2.00/\mathrm{GJ}}{0.75\mathrm{x}0.95}$	$2.807/GJ
	MSW	($0.96/GJ)	69.98%	$\frac{\$0.96/\mathrm{GJ}}{0.6998\mathrm{x}0.95}$	($1.444/GJ)

TABLE 6-9 (Cont'd)

Fuel Related Costs of Heat Production from Central Heating Stations

Station Heat Production Capacity	Fuel	Fuel Price in Central Canada	Annual Operating Efficiency	Effect of Efficiency on Price	Adjusted "Fuel-Cost" of Heat
$300\ \text{MW}_t$	Gas	\$4.28/GJ	84.00%	$\frac{\$4.28/\text{GJ}}{0.84\text{x}0.95}$	\$5.363/GJ
	Oil	16.10¢/L (41.81 MJ/L)	88.00%	$\frac{\$3.85/\text{GJ}}{0.88\text{x}0.95}$	\$4.605/GJ
	Coal	\$2.05/GJ	84.00%	$\frac{\$2.05/\text{GJ}}{0.84\text{x}0.95}$	\$2.569/GJ
	Wood	\$2.60/GJ	79.00%	$\frac{\$2.60/\text{GJ}}{0.79\text{x}0.95}$	\$3464/GJ
	Peat	\$2.00/GJ	75.00%	$\frac{\$2.00/\text{GJ}}{0.75\text{x}0.95}$	\$2.807/GJ
$1500\ \text{MW}_t$	Gas	\$4.28/GJ	84.12%	$\frac{\$4.28/\text{GJ}}{0.8412\text{x}0.95}$	\$5.356/GJ
	Oil	16.10¢/L (41.81 MJ/L)	88.00%	$\frac{\$3.85/\text{GJ}}{0.88\text{x}0.95}$	\$4.605/GJ
	Coal	\$2.05/GJ	84.00%	$\frac{\$2.05/\text{GJ}}{0.84\text{x}0.95}$	\$2.57/GJ

NOTE: Another part of this report contains a discussion of the losses incurred in the transmission and distribution systems of a district heating network. That discussion concludes that a weighted average loss as between high density (downtown core) areas, medium density areas (around the core) and low density areas, is about 5% of the heat supplied by the heating station to the network. This results in an efficiency of 0.95 for the whole network. The effect of this factor on the price of fuel is included in the above computation.

A comparison of the figures in the last (right hand) columns of Tables 6-5 and 6-9 indicates that the fuel-related cost of individual building heating is almost twice the fuel-related cost of heat supplied by district heating stations.

In both cases the figures do not take account of the capital and non-fuel O&M costs. The significance of the comparison lies in the fact that the cost of fuel always constitutes a major proportion of the total cost of heat supplied.

It should be mentioned that, since no furnace flue gas losses or start-up, shut-down and off-cycle losses are involved when heat is supplied to a building by a DH system, the heat supplied is used at 100% efficiency by the building.

Attention has already been drawn to the added advantage of district heating that lower grades of fuel, which are not suitable for transportation or as chemical feedstock, can be burned in central heating stations. That this constitutes a social and a national balance-of-payments benefit has long been recognized in Europe and the viewpoint is fast gaining support in Canada and the United States.

622 NON-CONVENTIONAL OPTIONS

Non-conventional fuel and energy resource options are:

- Solar energy
  - solar central thermal receiver
  - solar photovoltaic
  - solar pond
  - solar (thermal) panel
- Geothermal energy
- Nuclear energy
  - waste heat from nuclear power stations
  - slowpoke reactor
- OTEC
  - ocean thermal energy conversion
  - combination OTEC/Solar Pond
- Petroleum cokes and pitch
- Oil Shale
- Wind energy
- RDF (refuse derived fuel)
- Municipal and industrial sludges
- Low grade ambient heat from air and ground or surface water
- Low grade industrial and fossil-fired utility heat discharges
- Wave energy

Some of these fuel and energy resource options can be used to advantage with storage systems such as aquifer, rock, mineral oil and molten salt thermal energy storage systems.

Heat pumps and various forms of vapour compression technology are applicable to the upgrading of low grade gaseous and liquid heat resources in order to make them available for district heating systems. These, however, are systems and technologies rather than energy options which use electrical or steam driven prime movers. They have been discussed in Part 6.3 under system options.

Most of the non-conventional fuel and energy options listed above may in practice be applied to district heating or, as hybrid system aids to district heating only, in situations where circumstances or opportunities particularly favour their use. The following brief comment on each option will serve to illustrate this point.

.1 Solar Energy

Solar central thermal receivers are site specific installations, require high levels of solar insolation, large ground areas for heliostat arrays, and operate best in combination with rock, mineral oil or molten salt thermal energy storage systems. They are unlikely to become common to the Canadian scene. At their best in tropical locations they would operate at about 15% efficiency.

Solar photovoltaic and solar thermal panel systems are applicable to small capacity installations and may be used as hybrid aids to district heating. They would be installed in consumer buildings rather than at central heating stations, and would be owned and operated by building owners or residents. Along with passive solar systems and thermal energy storage systems, solar photovoltaic and solar thermal panel systems may, as they gain in economic viability, be more extensively used. It is necessary that projected DH systems take account of such possibilities within the areas they expect to serve, and review their impact upon the demand and consumption estimates for district heat for both space heating and domestic hot water.

.2 Geothermal Energy

Geothermal fluids, typically ranging in temperature from 30°C to 120°C, are being used as an energy resource in DH schemes in Europe and the United States. Studies conducted in Canada, principally for the National Research Council, indicate that, given appropriate economic and risk sharing incentives, geothermal energy provides a likely development opportunity for heating of mines and for large space heating applications.

A study of low temperature geothermal energy applications, conducted by Acres for NRCC(10), computed $3/GJ in 1983 dollars for the cost of heat from a geothermal doublet (a pair of wells for extraction of the fluid from, and its reinjection to, a geothermal acquifer). A doublet may be expected typically to yield a flow of 100-150 m^3/h. Where the extraction temperature is 100°C and the reinjection temperature is 40°C, the heat resource is equivalent to a heating station capacity of about 7.0 MW_t for a flow of 100 m^3/h.

Table 6-10 gives examples of typical geothermal production rates from existing operations. One of the tabulated operations is located at Creil, 50 km north of Paris. Figure 6-1 is a simplified flow diagram of the geothermal heat supply installation at Creil, which has been in operation since 1977.

TABLE 6-10

Typical Geothermal Production Rates from Deep Sedimentary Basins(10)

PROJECT	AQUIFER	FLOW	DEPTH	TEMP	COMMENTS
Poplar, Montana*	Madison	114m^3/hr	1825m	88°C	20HP submersible pump
Brown (1979)	Madison	11-320m^3/hr		up to 121°C	generally the hotter the water the less the flow
St. Mary's Hospital Pierre, S. Dakota	Madison	85m^3/hr	663m	41°C	
Dickenson* N. Dakota	Inyan Kara	275m^3/hr	1737m	71°C	122 on drawdown 275m pump set
Lemmon* S. Dakota	Madison	22-90m^3/hr	2141m	71°C	30m static level 150m pumpset depth
Malun Almont	Paris Basin	100m^3/hr	1800m	71°C	artesian
Villeneure	Paris Basin	170m^3/hr	1700m	60°C	pumped
Mont-de-Marsan France	Aquitane Basin, limestone, sandstone	125-265m^3/hr (300m^3/bar)	1850m	61°C	2-speed pump set at 25m depth in 13-3/8" casing, 9-5/8" liner
Blagnac France	Sandstone conglomerates	43m^3/hr (est. 50m^3/bar)	1575m	60°C	pump set at 190m depth in 13-5/8" casing, 9-5/8" liner
Creil	Paris Basin	135-300m^3/hr	1700m	56°C	pumped

* Application study, estimates only.

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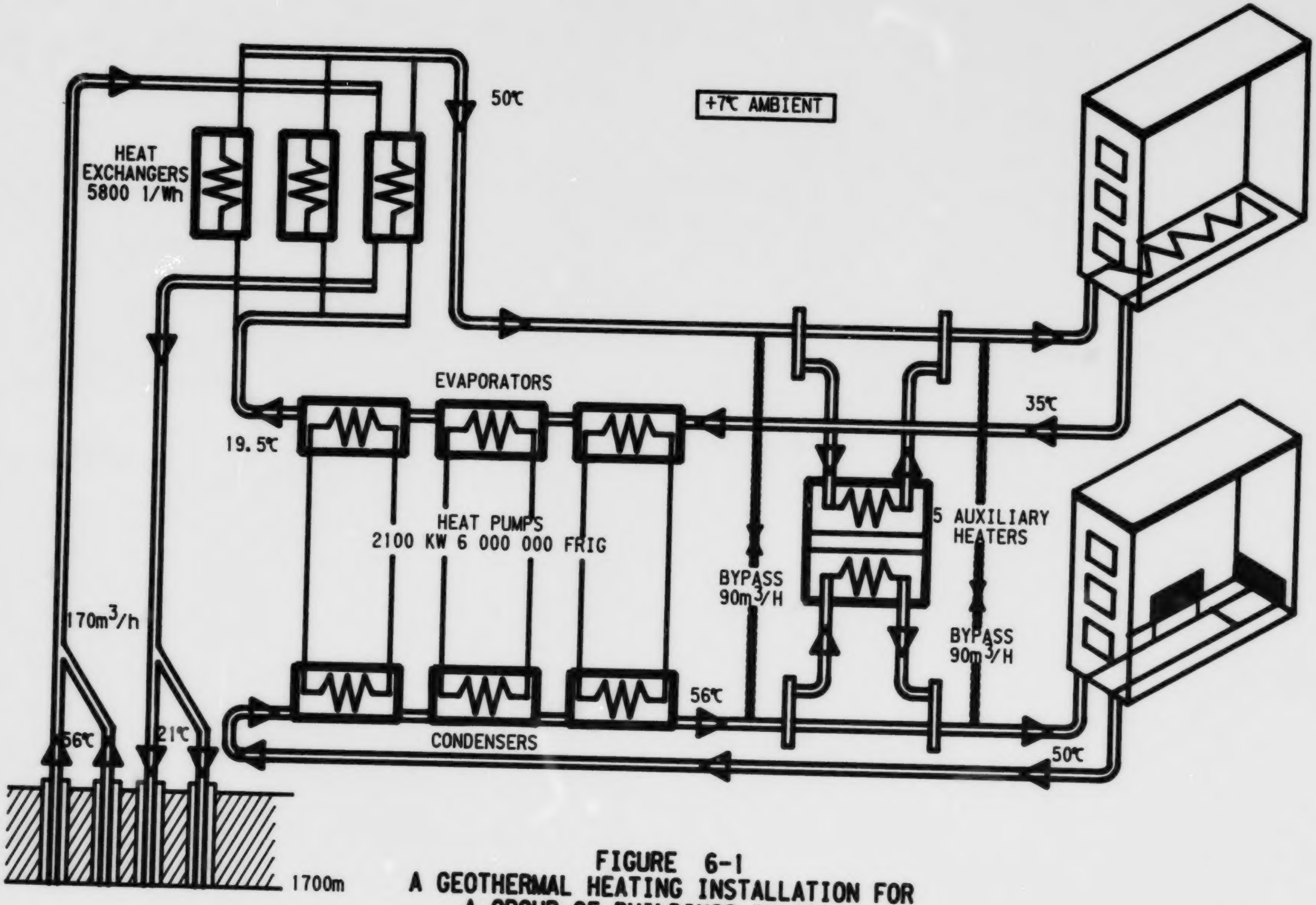
50℃
+7℃ AMBIENT
HEAT
EXCHANGERS
5800 1/Wh
EVAPORATORS
35℃
19.5℃
HEAT PUMPS
2100 KW 6 000 000 FRIG
5 AUXILIARY
HEATERS
BYPASS
90m3/H
BYPASS
90m3/H
170m3/h
56℃
56℃
21℃
CONDENSERS
50℃
1700m

FIGURE 6-1
A GEOTHERMAL HEATING INSTALLATION FOR
A GROUP OF BUILDINGS IN CRIEL,
50 km NORTH OF PARIS

Investigations conducted by the Energy Research Unit(10) of the University of Regina indicate considerable variations in basin structure and stratigraphic sequences beneath applicant sites. Only some beds have the requisite porosity, permeability and storage characteristics to be prospective geothermal reservoirs. For preliminary study purposes Acres assumed that the following geothermal fluid and production characteristics may be considered reasonable(10):

Geothermal gradient	30°C/km
Temperature range	60°-100°C
Production depth	2000-3300 m
Static water level	ground surface
Production flow rate	100*-150 m^3/h
Drawdown (7 yrs)	140 m*

The compositions of some geothermal fluids are given in Table 6-11 (229).

TABLE 6-11

Composition of Thermal Waters from Drill Holes Concentrations are in mg/Kg for Water Collected at Atmospheric Pressure from Discharge (229)

	1	2	3	4	5	6	7	8
Temp °C	216	260	250	300	340	340	215	324
Depth (m)	650	1030	830	945	1285	1600	–	1900
pH (20°C)	9.6	8.3	8.3	4.9	–	4.7	8.15	6.8
Li	0.3	11.7	13.2	–	19	215	5.15	42
Na	212	1050	1250	264	5820	50400	936	8270
K	27	210	210	144	1570	17500	131	2694
Rb	0.04	2.2	2.9	–	–	135	2.37	–
Cs	0.02	1.7	2.5	–	–	14	0.84	–
Mg	0.0	0.1	0.04	8.7	8	54	0.19	0.5
Ca	1.5	2.2	12	22.9	280	28000	12.3	240
Mn	0.00	0.009	0.015	–	–	1400	–	–
Fe	0.1	0.01	0.01	508	0.2	2290	–	–
F	1.9	7.3	8.4	–	–	15	–	–
Cl	197	1743	2210	12.4	10420	155000	1474	16710
Br	0.45	5.7	5.5	–	14.1	120	–	–
I	0.0	0.8	0.3	–	3.1	18	–	–
SO_4	61	8	28	1780	0	5	136	–
As	–	8.1	4.5	–	–	12	–	35
Total CO_2	55	128	17	26	1653	7100	47	–
Total SiO_2	480	805	670	635	740	400	864	838
Total B	0.6	48.2	28.8	61.1	12.4	390	24	346
Total NH_3	0.1	2.1	0.2	–	–	386	–	–
Total H_2S	7.3	1	1	tr	700	16	–	–

1. Hole G-3, Hveragerdi, Iceland
2. Drill Hole 2, Broadlands, N.Z.
3. Drill Hole 24, Wairakei, N.Z.
4. Hole 1, Matsukawa, Japan
5. Hole 5, Mexicali, Mexico
6. Hole 1, IID Salton Sea, U.S.A.
7. Well 9, Otake, Japan
8. Mahiao 1, Tongonan, Philippines

Reservoir porosity, permeability, thickness, continuity and pressure, along with well design, diameter, drawdown characteristics and downhole pump depth settings are among the factors which determine the production rate from a well. Flow rates therefore vary considerably for different reservoir formations and even for the same formation from region to region.

Disposal of geothermal fluids at the surface presents problems. The only acceptable solution appears to be re-injection to the basin. This reduces the chances of thermal and chemical pollution. However, significant chemical pollution may still result from the presence of CO_2 and H_2S gases, which are extracted along with the fluid as dissolved gases. Precautions must be taken to control and dispose of them.

Estimation of geothermal energy resource is, at this time, not an exact science. None of several methods currently in use is considered entirely proven and reliable. Every geothermal basin developed to date appears to have characteristics unique to itself, and the estimated recoverable resource is at best an order of magnitude figure even after the field has become operational.

A continuing program of measurement must be maintained even after exploitation has commenced. Understanding of reservoir behaviour and optimization of management practices is greatly dependent on constant measurement and integration of physical and chemical parameters.

Due to the high capital cost of geothermal resource development (the uncertainty of reservoir characteristics representing a major element of risk) the installation, to be viable, must be utilized at a high load factor. Seasonal utilization results in high unit costs for the energy extracted. For this reason geothermal energy operations in Canada may be combined heating and cooling or entirely base load systems. Fortunately the media temperatures required for space heating are similar to those required for cooling with absorption chillers. However, the demand for cooling is unpredictable. A significant number of Canadian customers who willingly pay for the necessity of seasonal space heating would be reluctant to pay for the luxury of space cooling, particularly when the additional cost of absorption chillers is involved.

Methods of seasonal storage for geothermal energy include aquifer thermal energy storage (ATES) systems and thermal energy storage in Solar Ponds.

Geothermal resources have been located in Pacific Canada (high and medium temperature resource), in Alberta and Saskatchewan (medium temperature) and in the Maritime provinces (low temperature). In this context, high temperature denotes: above 100°C, medium temperature: 50°C-100°C, and low temperature: below 50°C. Most of the resources in the Maritimes cannot be used for space and domestic water heating without the assistance of heat pumps.

It is well to recognize that geothermal energy utilization is an emerging technology in Canada, and that its prospective application is geographically restricted to favourable locations.

.3 Nuclear Energy from Power Stations

Heat available from nuclear power stations may take two forms. At the Bruce Nuclear Power Station in Ontario, Canada, there is a supply of steam in excess of station needs. This steam from the Bruce Energy Centre is available for use in an Industrial Park for space, water and process heating. Nuclear power stations also reject heat to ambient water from their condensers in a manner similar to fossil-fired power stations. This, however, is low-grade heat, ranging 5°C to 10°C above ambient water temperature, and requiring upgrading by heat pumps.

Such opportunity resources have strictly local applications. Capital investment, O&M costs, reliability and standby requirements have to be investigated on a case basis. At Bruce, for example, around 72 MW_t of steam capacity is available from the Energy Centre in Phase I and 288 Mw_t on completion of Phase II. This would provide space and domestic water heating for a population of about 12,500 people in the first phase and 50,000 when the expansion is completed. Figure 6-2 contains a flow diagram showing the position of the energy Centre within the scheme of the Bruce Nuclear Power Development.

Table 6-12 illustrates the cost of heat, energy projected by Ontario Hydro for consumers at the Bruce Energy Centre.

TABLE 6-12

Illustrative Rates for Heat Energy At Bruce Energy Centre

Year	\$ per 10^6 BTU	Percentage Increase Over Previous Year
1985	1.87	
1986	2.06	
1987	2.27	
1988	2.50	
1989	2.76	10.25% per year
1990	3.04	
1991	3.35	
1992	3.69	
1993	4.07	
1994	4.49	
1995	4.95	

Firm rates would be offered for the first 5 years (1985-89). Subsequently rates would be adjusted yearly.

Source: Ontario Hydro.

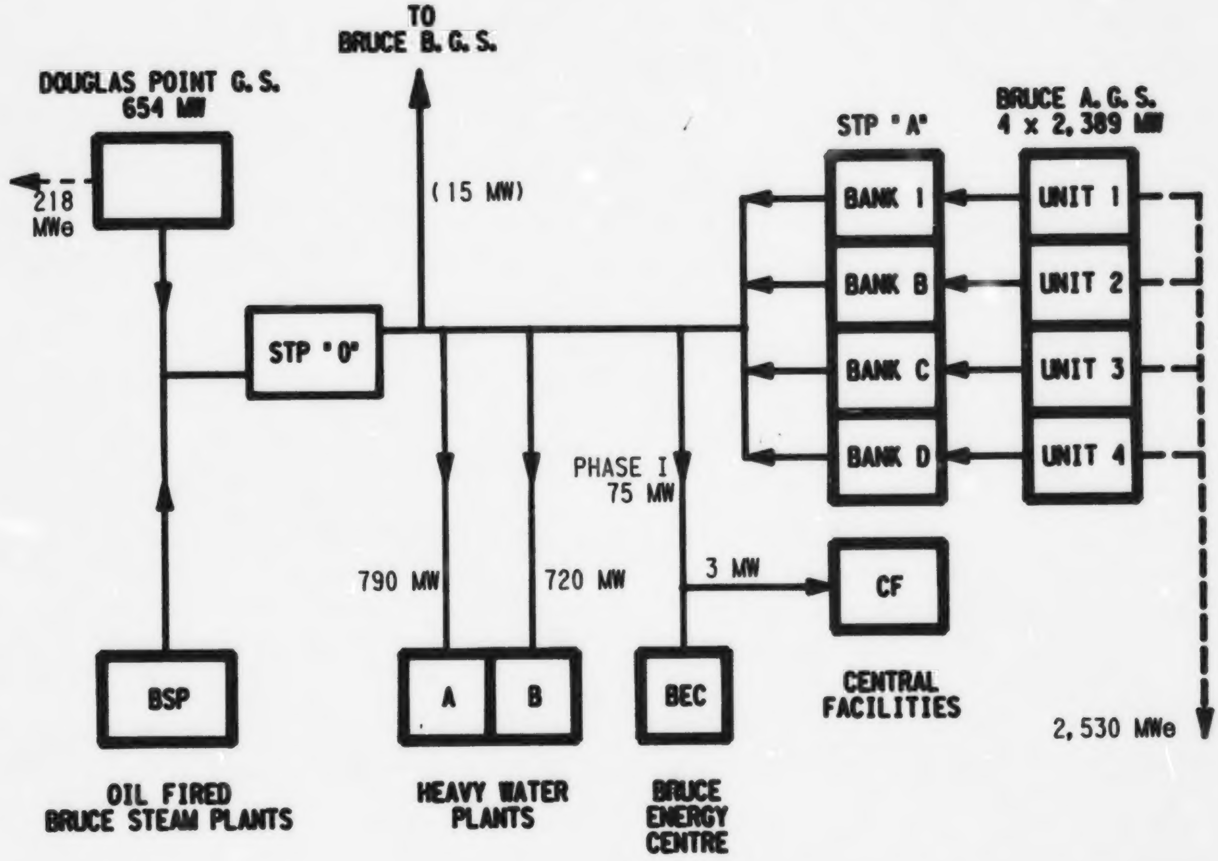
TO
BRUCE B. G. S.
DOUGLAS POINT G. S.
654 MW
218
MWe
(15 MW)
STP "A"
BRUCE A. G. S.
4 x 2,389 MW
BANK 1
BANK B
BANK C
BANK D
UNIT 1
UNIT 2
UNIT 3
UNIT 4
STP "0"
PHASE I
75 MW
790 MW
720 MW
3 MW
CF
BSP
A
B
BEC
CENTRAL
FACILITIES
2,530 MWe
OIL FIRED
BRUCE STEAM PLANTS
HEAVY WATER
PLANTS
BRUCE
ENERGY
CENTRE

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FIGURE 6-2
TYPICAL BRUCE NUCLEAR POWER DEVELOPMENT
SYSTEM SUPPLY/DEMAND

.4 Nuclear Reactors for Community Heating

Small nuclear reactors are being developed as heat producers for district heating systems. This application is discussed in Section 6310.

.5 Ocean Thermal Energy Conservation (OTEC) and OTEC/Solar Pond Combinations

.51 The OTEC Concept By using a vapour-compression plant and a cold water pipe long enough to span the temperature differential of the ocean, heat may be extracted from the water and utilized to power an engine that is similar in principle to a standard "heat engine" (turbine) normally used in the production of electricity.

An OTEC plant can be designed to operate as an "open" or "closed" cycle. In an open cycle, ocean water is used as the operating fluid. In the closed cycle, use is made of a working fluid, with a reasonably high vapour pressure at ambient temperature and having good heat transfer characteristics, such as ammonia, propane or freon.

.52 Technology Status This option may be eliminated in relation to Canadian DH schemes because demonstration of the technology has to-date been conducted on scales which were too small to have permitted system and equipment optimization. Gross to net power ratios of two demonstration units were in the range of 4 to 3.33. Closed-cycle systems of 50 kW and 120 kW gross produced 15 kW and 31 kW net respectively. Both operated at temperature differentials of 21-22°C. While parasitic pumping losses are high, it is estimated (Trimble, L.C. & Owens, W.L. of Lockheed Missile and Space Co. Inc.) that in commercial scale optimized plants the gross to net ratios could drop to around 1.5.

It is anticipated that combined OTEC/Solar Pond systems may prove technically and economically feasible. Operating at a higher temperature differential of 50°C, they would potentially raise the cycle and net efficiencies from approximately 7.5 and 2.5 respectively for pure OTEC to 21.5 and 11.5 for OTEC/SP. However, considerable flat coastal land would be required for the solar pond.

Argonne National Laboratory (Ahimaz & Cirillo Feb. 1983) reports that several studies for 300 to 400 MW OTEC plants produced capital cost figures ranging from 1980 U.S. $1,000 to $4,300 per kW installed, and O&M costs of 31 to 96 mils/kWh. A study by Meta Systems indicates a cost of $6,000 per kW installed for a 5 MW OTEC/SP plant. Such a plant would require about 160 acres of land for the solar pond.

.53 Environmental and Ecological Considerations No data on this subject has been developed to date. OTEC is generally assumed to be a "limitless" energy resource. How off-shore marine and biological life may be affected by the thermal impact of OTEC will probably warrant in-depth investigation as OTEC approaches commercial project status.

.6 Petroleum Cokes and Pitch

Two types of petroleum coke, delayed coke and fluid coke, are produced from heavy residuals of various petroleum cracking processes. Table 6-13 (22) gives selected analyses and typical heating values.

TABLE 6-13

Selected Analysis of Solid Fuels Derived from Oil[22]

ANALYSES (DRY BASIS), % BY WT	DELAYED COKE		FLUID COKE	
Proximate				
Volatile matter	10.8	9.0	6.0	6.7
Fixed carbon	88.5	90.9	93.7	93.2
Ash	0.7	0.1	0.3	0.1
Ultimate				
Sulphur	9.9	1.5	4.7	5.7
Heating value, Btu/lb	14,700	15,700	14,160	14,290

Both these materials are by-products of processes in which heavy residual oil is converted to lighter and more highly valued distillates which are flashed while the solid residue forms coke.

Depending on the feedstock and the process used, the characteristics of cokes vary widely as shown in Table 6-14 (Source: Combustion Engineering).

TABLE 6-14

Range of Fluid and Delayed Coke Characteristics

		FLUID COKE	DELAYED COKE
Moisture	%	-	3-12
Volatiles	%	3-6.5	10-20
Fixed Carbon	%	90-95	71-88
Ash	%	0.2-0.5	0.2-3.0
Sulphur	%	4.0-7.5	2.9-5.4
HHV, Dry	Btu/lb	14,100-14,600	14,100-15,600

Some cokes can be pulverized and fired and some cannot. Clearly the sulphur content may present problems of pollution abatement and expensive FGT systems may be required.

The tar sands plants at Fort McMurray in Alberta produce cokes. Suncor produces delayed coke in lump form which can be crushed and then fired as a pulverized fuel in boilers, although high SO_2 in the flue gases would have to be controlled. Combustion of this product in bubbling fluid beds has been considered. The Syncrude plant produces a fluid coke at around -1.0 mm grain size which is currently slurried and pumped out for disposal. It is proposed to test this material for combustion in circulating fluidized bed boilers. Analyses of these cokes are given below.

TABLE 6-15

Typical Ultimate Analyses of Delayed and Fluid Cokes in Alberta

	FLUID COKE	DELAYED COKE
Carbon	81.70	76.85
Hydrogen	1.79	3.47
Sulphur	6.55	4.64
Nitrogen	1.52	1.33
Ash	6.59	3.49
Oxygen (by diff)	1.85	1.07
Moisture	Dry *	9.15

* Moisture in fluid coke ranges 1.24% to 4.75%.

As an alternative to coke, petroleum pitch may be a by-product of processes which yield fuels of various characteristics from heavy residuals. The melting points of pitch vary and physically the substance may be soft and gummy or hard and friable. If the melting point is low, pitch may be heated and burned like heavy oil. If not, it may be pulverized or crushed for burning, possibly in cyclone furnaces.

Combustion of pitch presents problems. Pitch often contains about 600 ppm of vanadium and about 3.0% sulphur. Additives are required to condition the vanadium bearing ash deposits on superheater surfaces so that they can be cleaned by sootblowers. Another problem is the high viscosity which requires the fuel to be heated to high atomizing temperatures which sometimes causes coking in the fuel lines leading to the burners. Impurities in the ash from combustion of pitch, such as vanadium, sodium and chlorides are likely to increase high temperature corrosion problems.

Combustion of cokes and pitch in DH boilers should be undertaken with care, following detailed investigation and testing.

Petroleum cokes and pitch are difficult materials to use. They are mainly used as close to their production facilities as possible by refineries in special boilers. However, pollution abatement is expensive. Some refineries which produced these materials as by-products (at Port Hawkesbury, N.S., for example) are now closed.

If available, in excess of refinery requirement, these materials would create a disposal problem, and their prices, as fuels for prospective district heating schemes, would be subject to negotiation.

.7 Oil from Shale

Kerogens contained in shale, although good refinery feedstock, are not easily or cheaply recovered. There are two basic technologies. One consists of retorting the mined shale to decompose the kerogen, and the other of carrying out the same process in underground retorts, so as to eliminate mining, by recovering the oil and leaving the shale in-situ. Retorting the shale at about 875°F decomposes the kerogen to produce shale oil. Generally oil from kerogens can be refined to yield grades of gasoline, jet fuel and fuel oil. Production of a high heating value pipeline quality gas has also been demonstrated from Colorado shale oils.

Table 6-16 gives an analysis of oil shale from the green river in the Colorado-Utah-Wyoming area.

TABLE 6-16

Analysis of a Green River Oil Shale(22)

Physical properties		
Specific gravity, 60F/60F		2.3
Bulk density, 48 mesh, lb/cu ft		67.8
Oil shale assay,* % by wt		
Oil		10.3
Gas		2.5
Water		1.4
Organic residue		3.1
Mineral residue		82.7
Yield in oil, gal per ton		26.7
Mineral residue, wt % of raw shale		
Mineral CO_2 evolved		20.0
Mineral analysis of ash		
Silica	as SiO_2	26.4
Calcium	as CaO	17.1
Magnesium	as MgO	5.4
Aluminum	as Al_2O_3	6.6
Alkalies	as Na_2O & K_2O	3.7
Iron	as Fe_2O_3	2.6
Phosphorous & Vanadiaum	as P_2O_5 & V_2O_5	0.4
Sulphur	as SO_3	0.5

* Modified Fischer Assay

An interesting possibility for using shale is being investigated by the New Brunswick Electric Power Commission and Energy Mines and Resources, Ottawa. It is proposed that oil shale, from Albert County in the province of New Brunswick, be mixed with a low grade Maritime coal and fired in a circulating fluidized bed boiler at Chatham. Laboratory studies indicate that the shale will perform two functions in the fluid bed:

- The shale will partly, perhaps largely, replace the limestone (or dolomite) which would otherwise be used to absorb the high sulphur content of the low grade coal in order to reduce SO_2 emissions in the flue gas. The calcium and magnesium oxides in the shale will perform this function by combining chemically with sulphur in the coal to produce sulphates, which will be discharged and disposed of along with the ash.

- The shale will contribute its oil content as a combustible input to the furnace, thereby enhancing the overall heating value of the combined charge of coal and shale.

A typical analysis of Albert County Oil Shale is given in Table 6-17.

TABLE 6-17

Typical Analysis of Oil Shale from Albert County in New Brunswick
(Courtesy: New Brunswick Electric Power Commission)

Ultimate Analysis (wt %)	
Organic Carbon	10.59
Inorganic Carbon	3.24
Hydrogen	1.71
Sulphur	0.40
Oxygen	9.71
Nitrogen	0.12
Ash	73.73
Moisture	0.50
TOTAL	100.00
Ash Analysis (wt %)	
SiO_2	47.4
Al_2O_3	19.5
Fe_2O_3	7.3
CaO	14.9 (*)
MgO	5.5 (*)
Na_2O	3.3
K_2O	2.1
TOTAL	100.0

(*) Present in the original mineral matter as a carbonate.

Higher Heating Value (Btu/lb) = 2130

This development, if successful, will be beneficial to both the coal and shale industries in the province by utilizing two low grade provincial resources in a manner so that they combine advantageously to abate pollution from, and to enhance the fuel value of, each other.

The possibility of applying this technology in the future to DH schemes should be kept in mind.

.8 Wind Energy

Both vertical and horizontal axis wind generators are in commercial production. They are designed in small sizes up to 100 kW, medium sizes to 1,000 kW and large multi-megawatt sizes currently ranging from 5 MW to about 7.5 MW. Wind turbine generators are designed to cut-in at wind speeds, measured at 9.1 m (30 ft) above ground, ranging from around 3 m/s (7 mph) to 5.5 m/s (12.3 mph) and cut-out at high wind speeds ranging 15 m/s (34 mph) to 22 m/s (50 mph). When favourably located at sites where the seasonal variations permit viable operation of the turbines, power can be generated at about 30% of annual maximum rated capacity of the machine (i.e. 0.3 x rated capacity in kW x 8760 h = kWh/year).

However, most wind energy farms are remotely located and the electrical energy they generate is fed directly to power grids. At this time it is not anticipated that wind energy will contribute significantly to DH systems, although there may be occasional hybridized applications.

.9 Refuse Derived Fuel (RDF)/Processed Refuse Fuel (PRF)/Methane Recovery from Landfill

RDF is a fuel prepared from municipal or industrial solid waste by removing ferrous and non-ferrous metals, glass and other inclusions which do not have heating value, and shredding or otherwise reducing the heterogeneous mass into a more or less homogeneous material composed of small (about -1 cm) sized pieces. In the process the waste also loses some moisture and can either be compressed and baled for ease of transport, or made into briquettes under high pressure. RDF can be fired in semi-suspension or, if in briquettes, on grates. RDF has the virtue of more uniform combustion characteristics, as compared with MSW which is mass burned, due to its lower moisture content and more uniform size and heating value. The merits of RDF as compared with unprepared or treated municipal solid waste (MSW) should be subjected to techno-economic analysis in each case. One of the advantages claimed for RDF is that it can be burned in existing fossil-fuel or wood-firing boilers without the requirement of major retrofitting. However, this claim requires careful review in terms of corrosion and cleaning of boiler surfaces, ash collection and flue gas systems of the existing boiler in which it is proposed to fire RDF. It is also claimed as an advantage that RDF can be fired in combination with wood and other low grade fuels where they have similar size classifications.

As a prospective fuel for district heating, RDF should be reviewed as an opportunity option, particularly where significant industrial wastes are available for burning in existing boilers. If feasible, such an option could reduce the front end capital investment in the DH system.

The heating value and analysis of RDF is subject to wide variation depending on the waste source(s).

Whereas mass burning is the most popular method for recovering energy from municipal and industrial solid wastes, reduction of the waste to RDF or to PRF, and its subsequent combustion, has been attempted successfully in some cases and not so successfully in others. A selected list in Table 6-18 gives the status, as at September 1983, along with the source for further information, of several RDF and PRF projects.

The Table also names a few projects for recovery of methane from landfills. It will be seen that the capacity of the methane recovery projects is mainly in the small (below 10 MW) range. (Source for Table 6-18 is City Currents September/October 1983, published by the U.S. Conference of Mayors).

It will be seen from Table 6-18 that MSW, RDF, PRF are sometimes mixed with other fuels and/or wastes, including municipal and other sludges, either for the purpose of improving combustion characteristics or for combined utilization of another local energy resource.

TABLE 6-18

Selected RDF/PRF and Refuse Derived Methane Projects

Location and Major Participants	Processes	Products & Uses	Capacity (tons per day)	Capital Costs ($ million)	Status	Source
Bridgeport Conn. Resources Recovery Auth; Occidental Petroluem Corp. and Combustion Equipment Assoc. (designer/operator); Greater Bridgeport Regional Solid Waste Commission	Shredding, air classification, magnetic separation, Eco-Fuel II production process	Eco-Fuel II (powdered) fuel) for use in utility boiler, ferrous metals	1800	53	Plant is closed due to CEA's financial difficulties; negotiations with Occidental concluded unsuccessfully; presently in arbitration	Lynn C. Healey Executive Assistant Conn. Resources Recovery Authority 179 Allyn St. Hartford, Conn. 06103
Orange County (Walt Disney World) U.S. Dept. of Energy, Idaho Operations Office Reedy Creek Utilities Co. (owner/operator); Andco, Inc.	Slagging pyrolysis incineration (Andco-Torrax)	High temperature hot water for heating and cooling at Walt Disney World	100	15	Testing completed on simulated nuclear wastes and municipal waste; not operating due to unfavorable economics	Carl P. Gertz Project Manager U.S. Dept. of Energy 550 Second St. Idaho Falls, Idaho 83401
East Bridgewater City of Brockton and nearby towns; Combustion Equipment Assoc. (designer); PCN Enterprises (owner)	Shredding; air classification, magnetic separation; other mechanical separation and production of Eco-Fuel II	Eco-Fuel II for industrial boiler; ferrous metals	300 tpd being landfilled, with excess trucked to other landfills	10 -12	Plant has been sold by CEA to OCN Enterprises; currently operated as a landfill, but may be reactivated into a resource recovery facility	M.G. Magoulas Corp. Vice Pres. Engineering Combusion Equipment Assoc. 136 East 57th St. New York, N.Y. 10022

TABLE 6-18 (Cont'd)

Location and Major Participants	Processes	Products & Uses	Capacity (tons per day)	Capital Costs ($ million)	Status	Source
Haverhill & Lawrence Refuse Fuels (owner); BE&C Engineers, Inc. (Boeing subsidiary) (design & construction); Cities of Haverhill & Lawrence & other communities in service area	Shredding, magnetic separation, trommel screening at recovery facility in Havehill; burning RDF for co-generation of steam and electricity in Lawrence	Steam and electricity for industrial use; surplus electricity sold to utility	1300	99.5	Under construction; operations schedule for late 1984	James E. Ricci, Vice Pres. Refuse Fuels, Inc. P.O. Box 18 Bradford, Mass. 01830
Rochester Town and several nearby communities; Energy Answers Corp. (owner); Smith & Mahoney, P.C., and Gordon L. Sutin Assoc. (designers)	Shredding, magnetic separation, burning PRF in semi-suspension stoker-grate boiler, nonferrous recovery from ash, generation of electricity	Electricity for sale to Commonwealth Electric; ferrous and nonferrous metals	1500	136	Contracts for waste being signed; financing being arranged; construction expected to begin in 1984	Dr. George M. Ma President Energy Answers Corp. 1 Steuben Place Albany, N.Y.. 12207
Detroit City; Combustion Engineering, Inc.	Flail milling, trammel screening, secondary shredding, burning RDF in on-site dedicated boilers, electricity generation in 47 Mw turbo-generator	Steam for Detroit Edison's central heating system, electricity for sale to Detroit Edison; ferrous metals	3000	150	Negotiating with Combustion Engineering prior to contract signing tax counsel review and permit applications in process; preparing a revenue bond issue with equity participation to finance the facility	Michael Brinker Dept. of Pulic Works City of Detroit City-County Bldg. Rm. 513 Detroit, Mich. 48226

TABLE 6-18 (Cont'd)

Location and Major Participants	Processes	Products & Uses	Capacity (tons per day)	Capital Costs ($ million)	Status	Source
Duluth Western Lake Superior Sanitary District (owner/operator); Consoer, Townsend & Assoc. (designer)	Shredding, magnetic separation, air classification, secondary shredding fluidized bed incineration of RDF and sludge	RDF, ferrour metals, steam for heating and cooling of plant and to run process equipment	400 of MSW; 340 of 20% solids sewage sludge	19	Refuse processing facility temporarily shut down due to explosion in 7/82; other fuels being used to incinerate sludge and produce steam	John Klaers Western Lake Superior Sanitary Dist. 27th Ave. West & The Waterfront Duluth, Minn. 55806
Reno Washoe County, cities of Reno and Sparks; NEWEST, Inc. (owner, operator, designer)	Pyrolysis	Carbon char (K-Fuel) for use as coal substitute; glass, ferrous metals, aluminum	250 (Phase I) 1000 (Phase II)	32	Phase I construction to begin 9/83, with operation 9/84; expansion to 1000 tpd expected by 1988	Aldred J. Gangi President NEWEST 27 Archer St. Lawrence, MA 01841
Albany City (owner) and 13 nearby communities; Smith & Mahoney (designer) Aenco, Inc. (processing plant operator); N.Y. State (steam plant owner/operator)	Processing plant; shredding magnetic separation; steam plant; burning PRF in stoker-grate boiler; ash processing center; ferrous nonferrous & aggregate recovery from boiler ash	Processed refuse fuel (PRF), steam for heating and cooling state offices, ferrous & nonferrous metals, boiler aggregate	D-750 tons per shift T-750 tons per shift	28.2 (11.6 processing plant; 15 steam plant 1.6 ash processing center)	Operational	Patrick Mahoney Smith & Mahoney, P.C. 79 N. Pearl St. Albany, N.Y. 12207

TABLE 6-18 (Cont'd)

Location and Major Participants	Processes	Products & Uses	Capacity (tons per day)	Capital Costs ($ million)	Status	Source
Hempstead Town; Hempstead Resources Recovery Corp. (subsidiary of Parsons & Whitemore, Inc.) (owner/operator)	Hydrasposal (set pulping), magnetic and other separation, burning of RDF in air-swept spout spreader stoker boilers	Electricity from utility owned turbine generators, color-sorted glass, aluminum, ferrous metals	2000 (11,000 tons/week)	130	Temporarily shut down by joint agreement between Town and HRRC until EPA establishes uniform standards or guidelines for testing of dioxins	James L. McGiffin General Manager Hempsteam Resources Recovery Corp. P.O. Box 5010 Roosevelt Field Station Garden City, East, N.Y. 11530
Niagara Falls Hooker Energy Corp. (Occidental Chemical Corp.) (owner/operator)	Shredding, air classification, magnetic separation, burning shredded refuse	Steam for use by chemical plant; electricity sold to power company grid; ferrous metals	D-2000 T-1500	100+	Operational	Gary F. Blasius Plant Manager Hooker Chemical Co. P.O. Box 344 Niagara Falls, N.Y. 14302
New Hanover County New Hanover County (owner); Clark-Kenith Co. Charles R. Velzy Assoc. (designer); George Campbell Assoc.	Mass burning in waterwall boilers; cogeneration of steam and electricity	Steam for use by W.R. Grace Co. (agrochemical mfr); electricity for sale to Carolina Power & Light	200	13 (approx.)	Under construction; start-up expected in Fall 1984	Ed Hilton Director Engineering & Facilities New Hanover County 320 Chestnut St. Room 601 Wimington, N.C. 28401

TABLE 6-18 (Cont'd)

Location and Major Participants	Processes	Products & Uses	Capacity (tons per day)	Capital Costs ($ million)	Status	Source
Columbus City (owner/operator); Alden E. Stilson Assoc. (designer)	Shredding, magnetic separation, burning of shredded refuse with supplemental coal in semi-suspension stoker-grate boiler to produce steam and generate electricity	Electricity for city customers	2000 (3000 peak)	175	Under construction; operation expected in Fall 1983	Henry A. Bell, P.E. Superintendent Div. of Electricity City of Columbus 90 W. Broad St. Columbus, Ohio 43215
Oklahoma City City; CMI Energy Conversion Systems (owner/operator/designer)	Phase I-shredding, ferrous & nonferrous metals separation; thermal reduction (burning in rotary drum furnace) and electricity generation Phase II - anerobic digestion of organic msw & sewage	Electricity & methane gas for sale to Okla. Gas & Electric Co.; ferrous & nonferrous metals	5600 tons per week (Phases I & II)	29	Phase I startup testing completed; continuous operation expected to begin in late 1983; preparing for construction of Phase II	Chester Brooks CMI Energy Conversion Systems, Inc. 2525 Northwest Expressway Suite 108 Oklahoma City, Okla. 73112
Harrisburg City (owner/operator); Gannett, Fleming, Corddry and Carpenter, Inc. (designer)	Mass burning of MSW and sewage sludge in waterwall furnace, bulky waste shredding (steam driven), magnetic separation	Steam for utility-owned district heating system and for city-owned sludge drying system, ferrous metals	D-720 T-520	8.3	Operational; sludge drying facility in test	Paul W. Bricker Gannett, Fleming Cordry and Carpenter, Inc. P.O. Box 1963 Harrisburg, PA 17105

TABLE 6-18 (Cont'd)

Location and Major Participants	Processes	Products & Uses	Capacity (tons per day)	Capital Costs ($ million)	Status	Source
Petersburg United Bio-Fuel Industries, Inc. (owner); Teledyne National (designer) Raphael Katzen Assoc. Foster Wheeler Synfuels Corp.	Phase I-shredding, magnetic and other separation, burning of RDF for 25 MW electricity generation; Phase II-ethanol production from corn, 20 million gal/yr or possibly 50 tpd cellulose-alcohol R&D facility; Phase III-ethanol production using licensed process of enzymatic hydolysis of cellulose to alcohol, 37.5 million gal/yr.	Phase I-ferrous and non-ferrous metals, glass, electricity for sale to utility, steam for in-plant use; Phase II & III ethanol, CO_2 dried grain supplement (DGS), distiller's dried grain supplement (DDGS)	2000 (peak) 1350 initial	100 (Phase I) (Phase II) (Phase III)	Preliminary design completed; groundbreaking expected in late 1983 with start-up 22 months later for Phase I	Francis B. Richerson V.P. of Engineering United Bio-Fuel Industries Inc. P.O. Box 1312 Richmond, Va. 23210
Toronto Ontario Ministry of the Environment (owner); Browning Ferris Industries (operator); Kiborn Ltd. (designer) (Mfr. Consumat)	Shredding, air classification, secondary shredding, screening, mass burning in modular incinerator with heat recovery, ferrous cleaning; also transfer operation	Ferrous metal, RDF, compost; hot water for plant heating	Resource recovery-220; transfer facility-600	15	Operational since 3/77	Neal R. Ahlberg Supervisor Ontario Centre for Resource Recovery 35 Vanley Cres. Downsview, Ont. M3J 2B7

TABLE 6-19
Methane Recovery from Landfills

Location and Major Participants	Output or Gas Produced; Million ft^3 day	Capital Costs ($ millions)	Status	Source
Brea (Olinda Landfill) Getty Synthetic Fuels, Inc.; Orange County	Gas to power 5300 KW generator; electricity sold to Cal. Edison	N/A	Operation scheduled for late 1984	William R. Taylor Getty Synthetic Fuels, Inc. 2750 Signal Parkway Signal Hill, Calif. 90806
Carson Watson Biogas Systems; SCS Engineers, Inc.	Medium Btu gas to power generators, producing electricity for sale to So. Cal. Edison (1.7 Mw)	N/A	Collection system complete; operations expected in Oct. 1984	Bryan A. Stirrat National Engineering Co. 255 N. Hacienda Blvd. Industry, Calif. 91744
Carona Watson Biogas Systems; Lockman & Assoc.	Medium Btu gas to power generators, producing electricity for sale to utility (5 Mw)	N/A	Contracts signed with City and southern Calif. Edison; operation expected in March 1985	Bryan A. Stirrat National Engineering Co. 255 N. Hacienda Blvd. Industry, Calif. 91744
Los Angeles (Bradley East Landfill) Genstar Gas Recovery Systems, Inc.	Medium Btu gas used as supplemental fuel in steam generating plant by L.A. Dept. of Water & power 3.0	N/A	Operational since 9/80	Kenneth Wuest Genstar Gas Recovery Systems, Inc. 177 Bovet Rd. Suite 550 San Mateo, Calif. 94420
Monterey Park Getty Synthetic Fuels, Inc. Operating Industries, Inc. Southern California Gas Co.	High Btu gas for sale to So. Cal. Gas Co.; 4.0	N/A	Operational since 8/79	William R. Taylor Getty Synthetic Fuels, Inc. 2750 Signal Parkway Signal Hill, Calif. 90806
Mountain View City of Mountain View; EPA; Pacific Gas & Electric Co. Dept. of Energy	High Btu gas; 0.5	.85	Demonstration plant; currently operating and producing 0.3 MMSCFD of treated gas with a HHV of 850-950 Btu/SCF; expansion of system and modernization of plant underway, will boost capacity to 1.0 MMSCFC	Max Blanchet Pacific Gas & Electric Co. 245 Market St. San Francisco, Calif. 94106

TABLE 6-19 (Cont'd)

Location and Major Participants	Output or Gas Produced; Million ft^3 day	Capital Costs ($ millions)	Status	Source
San Jose Genstar Gas Recovery Systems, Inc. Browning-Ferris Industries	Medium Btu gas used as fuel for motor generator; electricity sold to utility (2.0 MW)	N/A	Operation expected 10/83	Kenneth Wuest Genstar Gas Recovery Systems, Inc. 177 Bovet Rd. Suite 550 San Mateo, Calif. 94420
Sun Valley (Sheldon-Arleta Landfill Gas Recovery Project) City of Los Angeles Department of Public Works and Water & Power	Low Btu gas used as fuel by L.A. Dept. of Water & Power; 1.5	2.5	Operational	Mike Miller Senior Sanitary Engineer L.A. Bureau of Sanitation Room 1410, City Hall East Los Angeles, Calif. 90012
Winston-Salem City	Medium Btu gas used as supplemental fuel in dual-fuel diesel engine to generate electricity for sewage treatment plant	Less than $25,000 for wells and pipeline	Operational since 9/81	Lee Byerly Supervisor Archie Elledge Wastewater Treatment Plant 2801 Griffith Rd. Winston-Salem, N.C. 27103
Oregon City Rossman's Landfill (owner); CH2M Hill (engineers)	Raw landfill gas (400 Btu/cf) 2.6	.5 (collection system only)	Collection system completed; negotiating with potential users for the recovered gas	Jack W. Parker President Rossman's Landfill, Inc. 1101 17th St. Oregon City, Ore. 97045
Brattleboro New England Alternate Fuels	Gas to power generators (300 KW); electricity sold to Central Vermont Public Service	0.365	Operational since 8/82; adding more generating capacity	Louis Audette New England Alternate Fuels P.O. Box 921 Brattleboro, Vt. 05301

TABLE 6-19 (Cont'd)

Location and Major Participants	Output or Gas Produced; Million ft^3 day	Capital Costs ($ millions)	Status	Source
Kitchener, Ontario Regional Municipality of Waterloo (owner); Bestpipe, Div. of Lake Ontario Cement Ltd; Federal Government of Canada; Province of Ontario	Medium Btu gas (approx. 39 MM ft^3/year) for use as boiler fuel by Bestpipe	.53	Phase I complete but not operating continuously due to poor gas production from landfill site; Phase II construction in doubt	John Pawley Director of Engineering Operations Regional Municipality of Waterloo Marsland Centre Waterloo, Ontario N2J 4G7

.10 Low Grade Ambient Heat Resources

Low grade ambient heat resources are mainly air, water and soil.

Air is used as a heat resource by heat pumps which operate at decreasing "coefficients of performance" (COP) as the air temperatures reduce from above freezing to below freezing. Most residential heat pump installations are so designed that they can provide all the heating required by the building as long as ambient air temperature remains above a specific temperature, such as -4°C in some cases. Below this temperature heat pumps perform with less economy and, therefore, when ambient air temperatures fall below this level, supplementary electrical heating is designed to switch into the system.

Due to the variation in performance (capacity and efficiency) with changes in ambient source temperatures, the seasonal performance factor (SPF) of heat pumps is lower than the steady state performance factor, otherwise called the coefficient of performance (COP) at a specified temperature.

Another ambient heat resource, surface or sub-soil water is, when flowing, always at temperatures above freezing. Where river, lake, pond or well waters can be tapped as heat sources, heat pump installations can be designed to use these heat sources in winter for heating and as heat sinks in summer for air conditioning.

Soil or ground heat, preferably below frost level, is a third source of ambient heat. In Sweden, for example, the small heat pump market is dominated by electrically driven heat pumps which use pipes laid horizontally in the ground to extract heat from the soil. Frost level in the ground is influenced by many factors, including:

- ambient air temperature;

- type of soil (sandy loam and gravel soil has a lesser capillary action and drains better, so that frost does not penetrate greatly below the surface);

- ground water table.

Air temperatures exert a major influence on water and soil temperatures. Figure 6-3 (113) compares annual cumulative durations of ambient air temperatures for selected countries.

[100,77]DSS63 .DGN

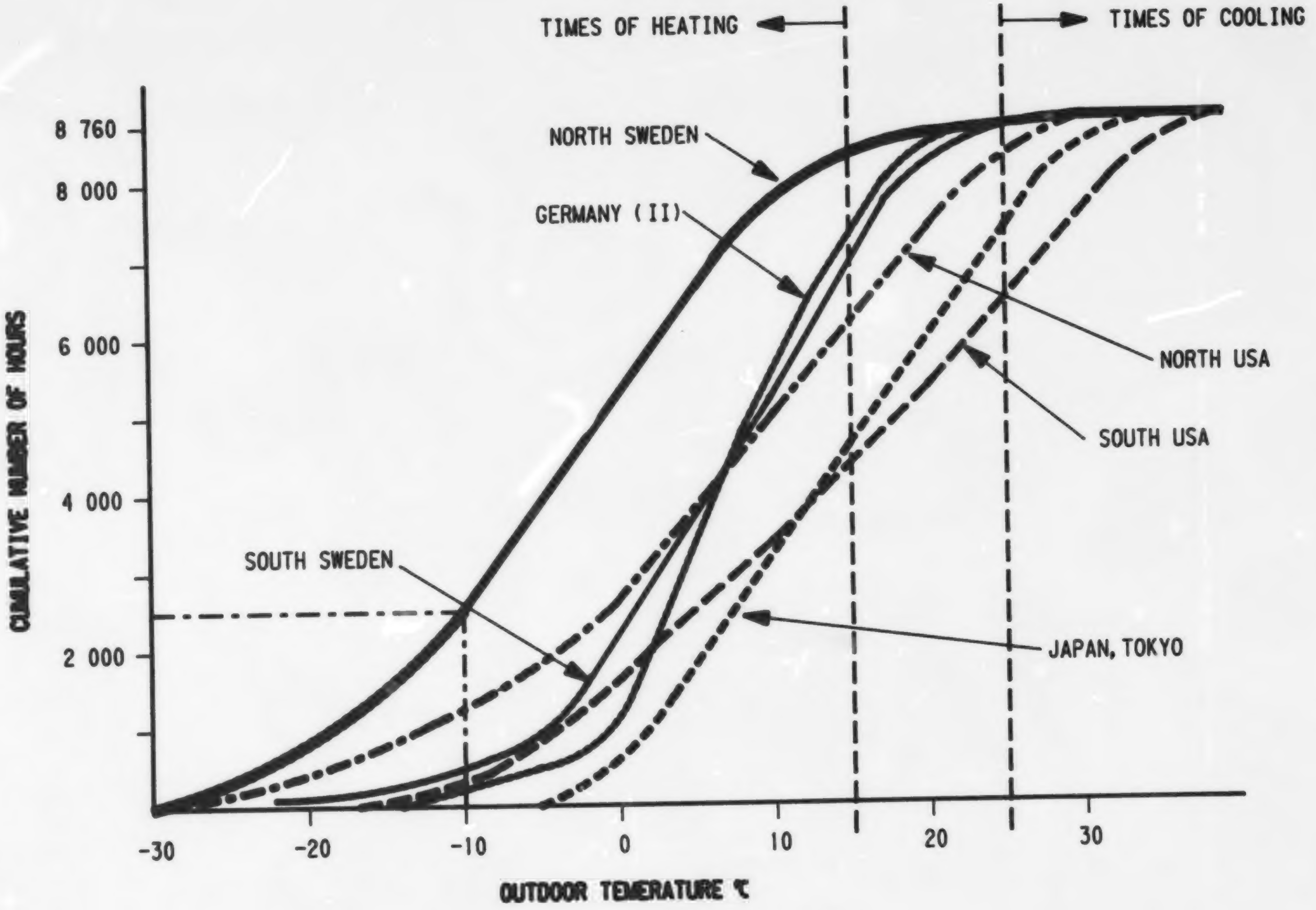

FIGURE 6-3
CUMULATIVE DEGREE HOURS FOR
A NUMBER OF REPRESENTATIVE COUNTRIES

The diagram in Figure 6-3 (113) demonstrates the rigor of the climate in northern Sweden, which is similar to northern Canada, when compared with that of northern U.S.A., which is similar to southern Canada. The low seasonal performance factor (SPF) of heat pumps mitisates against their being an economic option in the more rigorous northern climates.

Further discussion of heat pumps is contained in Section 634.

.11 Low Grade Heat from Municipal, Industrial and Utility (Other than Ambient) Sources

Low grade heat sources other than ambient are emissions and effluents from municipal, industrial and utility processes. These include:

- solid effluents, such as sludges from pulp and paper and other industrial plants;
- effluents from municipal sewage plants;
- liquid and gaseous effluents from industrial plants, nuclear and fossil-fired electrical power generating stations.

Sludges can be dried and burned or combusted in wet oxidation systems to produce heat for DH systems. Sludge with low heating value can sometimes be mixed with other locally available fuels in order to increase the overall energy density of the fuel and thereby reduce the boiler size and cost. Sludge must be investigated strictly as a local opportunity option since, like any low energy density fuel, it is not economic to transport it over major distances.

The possibility of slurry piping of sludge should be reviewed. If the sludge can be slurried, like peat, at about 9% solids concentration, then it may be pumped to the heating station, dried and fired in a DH boiler or subjected to wet air oxidation or wet carbonization to raise steam or hot water for district heating. These are, however, very specialized systems, and are dependent for techno-economic feasibility on numerous variables individual to each case.

The low-grade heat in liquid effluents from municipal sewage treatment plants can be upgraded by heat pump installations for DH service. Several large heat pump installations in Sweden serving district heating networks are cited below in Table 6-20 (Courtesy: ASEA/Stal-Laval). It will be seen that some plants use sewage treatment effluent; others use sea water, lake water, industrial waste water or combinations of these low grade effluents.

TABLE 6-20

Examples of Large Swedish and Finnish Heat Pump Installations Using Low Grade Liquid Thermal Resource

Ludvika - 11 MW	
Heat source	Lake water
Flow	1300 kg/s
Design temperature	2°C
Evaporator type	Panel evaporator
Heat recipient	The heating net at ASEA
Flow	400 kg/s through condenser
Temperature	50-70°C

TABLE 6-20 (Cont'd)

Ludvika - 11 MW (Cont'd)	
Output	11 MW
Average COP	3
Commercial operation	October 1982
Uppsala - 39 MW	
Heat source	Treated sewage water
Flow	500 kg/s through each evaporator
Temperature	9-18°C
Evaporator type	Tube evaporator
Heat recipient	The district heating net in Uppsala
Flow	400 kg/s through each condenser
Temperature	50-70°C
Output	3 x 13 MW
Average COP	3.2
Commercial operation	October 1982
Stockholm (Vartan) - 15 MW	
Heat source	Sea water
Flow	1200 kg/s
Design temperature	2°C
Evaporator type	Panel evaporator
Heat recipient	The district heating net in Stockholm
Flow	400 kg/s through condenser
Temperature	45-70°C
Output	15 MW
Average COP	3.5
Commercial operation	September 1983

TABLE 6-20 (Cont'd)

Malmo - 40 MW	
Heat source	Treated sewage water
Flow	500 kg/s through each evaporator
Temperature	8-20°C
Evaporator type	Tube evaporator
Heat recipient	The district heating net in Malmo
Flow	400 kg/s through each condenser
Temperature	50-70°C
Output	3 x 13 MW
Average COP	3.4
Commercial operation	November 1983
Upplands Vasby - 22 MW	
Heat source	Lake water
Flow	2500 kg/s
Design temperature	1.8°C
Evaporator type	Panel evaporator
Heat recipient	The district heating net in Upplands Vasby
Flow	200 kg/s through each condenser
Temperature	50-80°C
Output	2 x 11 MW
Average COP	3.0
Commercial operation	April 1984
Sandviken - 12 MW	
Heat source	Industrial cooling water
Flow	390 kg/s
Design temperature	15-25°C
Evaporator type	Tube evaporator
Heat recipient	The district heating net in Sandviken
Flow	324 kg/s through condenser
Temperature	60-80°C
Output	12 MW
Average COP	3.6
Commercial operation	April 1984

TABLE 6-20 (Cont'd)

Umea - 34 MW	
Heat source	Treated sewage water and industrial waste water
Flow	200-500 kg/s
Design temperature	10-16°C
Evaporator type	Tube and panel evaporator
Heat recipient	The district heating net in Umea
Flow	400 kg/s through each condenser
Temperature	45-80°C
Output	2 x 17 MW
Average COP	3.1
Commercial operation	November 1984
Lund Geo 1 - 20 MW	
Heat source	Geothermal water
Flow	440 kg/s through evaporator
Design temperature	23°C
Evaporator type	Tube evaporator
Heat recipient	The district heating net in Lund
Flow	700 kg/s through condenser
Temperature	60-80°C
Output	20 MW
Average COP	3.4
Commercial operation	January 1985
Borlange - 12 MW	
Heat source	Sewage water from pump and paper industry
Flow available	330 kg/s
Design temperature	15-25°C
Evaporator type	Panel evaporator
Heat recipient	The district heating net in Borlange
Flow	400 kg/s through condenser
Temperature	65-80°C
Output	12 MW
Average COP	3.0
Commercial operation	January 1985

TABLE 6-20 (Cont'd)

Nystad Finland - 7 MW	
Heat source	Treated sewage water and sea water
Flow	600 kg/s
Design temperature	0.5°C
Evaporator type	Panel evaporator
Heat recipient	The district heating net in Uusikaupunki, Finland
Flow	30-120 kg/s
Temperature	55-80°C
Output	1 MW heat pump + 10 MW electric boiler
Average COP	2.9
Commercial operation	April 1985
Stockholm Martensdal - 100 MW	
Heat source	Treated sewage water
Flow	1.8-4.9 kg/s
Design temperature	7-18°C
Evaporator type	Tube evaporator
Heat recipient	The district heating net in the southern parts of Stockholm
Flow	800 kg/s through each condenser
Temperature	55-85°C
Output	2 x 20 + 2 x 30 MW
Average COP	3.4
Commercial operation	November 1986
Jarfalla - 40 MW	
Heat source	Sea water
Flow	5500 kg/s
Design temperature	1.5°C
Evaporator type	Panel evaporator
Heat recipient	The district heating net in Jarfalla
Flow	400 kg/s through each condenser
Temperature	45-85°C
Output	2 x 20 MW
Average COP	3.0
Commercial operation	November 1985

Some of the plants listed are in commercial operation, while others are at various stages of procurement or construction; but in all cases orders have been placed, which indicates that feasibility has been established in each case. While the energy price scenario and the fuel structure in central and western Canada differs from that in Scandinavia, the situation in Atlantic Canada is similar enough for the examples cited to be of interest.

6.3 SYSTEM OPTIONS

631 CENTRAL HEATING PLANTS - GENERAL

The main purpose of the central heating plant is to provide the heating medium (hot water is considered for this study) to be circulated around the DH network. In addition to heating, the hot water may also be used in absorption type systems to provide air conditioning during the cooling season. Many systems installed in the United States would not be feasible without consideration of the cooling loads during the summer months. However, due to the time and budget restrictions of this study and the generally longer and more severe heating seasons in Canada, only district heating is considered here.

The type and number of units included in a central heating plant is very site specific, and dependent on such factors as heat load requirements, electricity and cooling loads (if to be provided by the same station), greenfield or retrofit situation, anticipated future expansion of system, type of fuels available, etc.

The heat load output of a central heating plant over the course of the year is illustrated on a heat load duration curve. The curve represents the hours of heat loads and the cumulative hours per year at a particular load. The total annual heat output of the district heating plant is the area under the curve. A typical heat load duration curve is illustrated on Figure 6-4.

It is obvious that the shape of the heat load duration curve directly affects the type and number of units in the heating station and the overall capacity factor. The station must be designed to provide the maximum heat load requirement, but also operate efficiently for the largest part of the year when the heat requirement

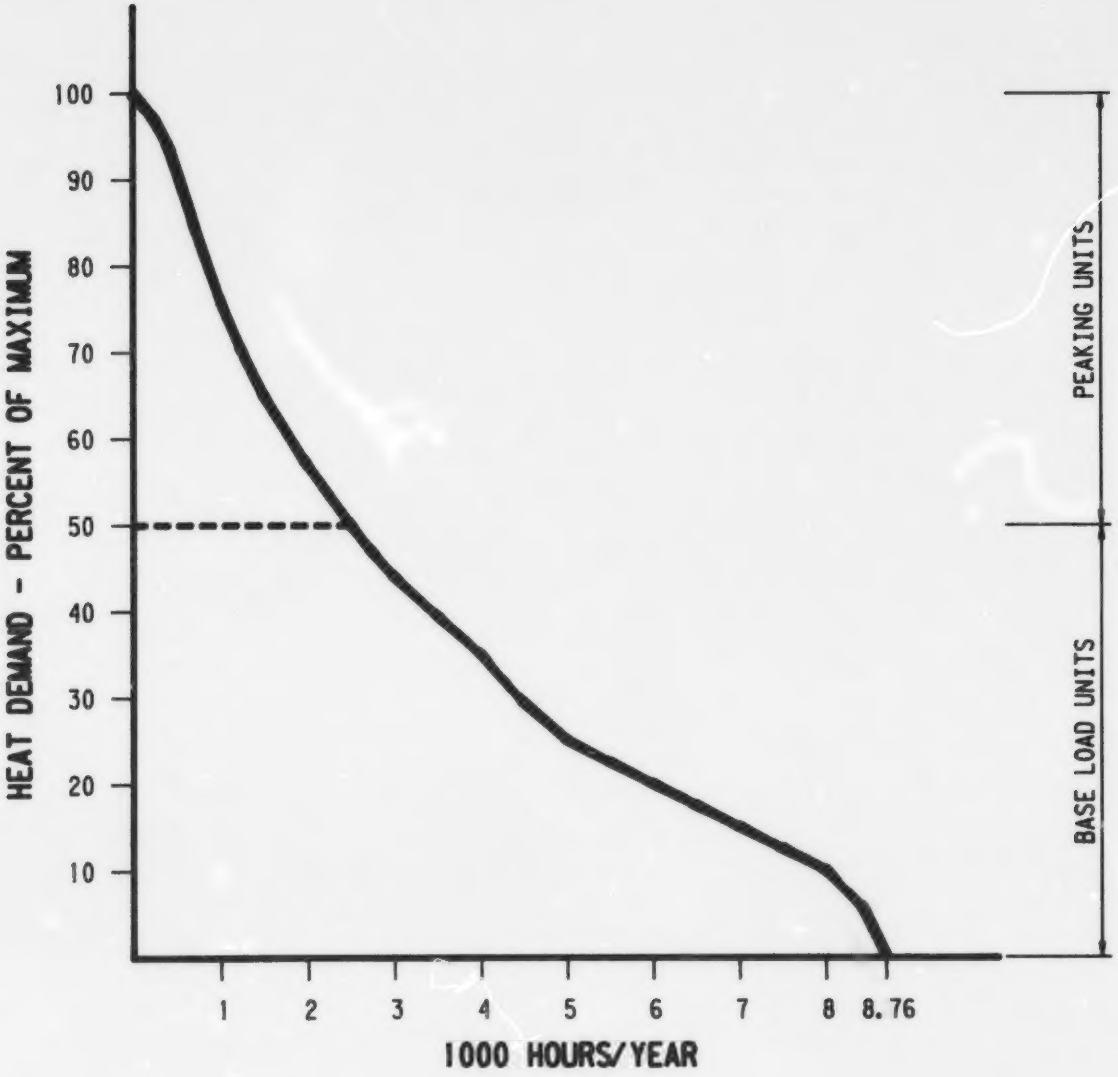

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FIGURE 6-4
HEAT LOAD DURATION CURVE

is much lower. In general, the heating station consists of base load and peaking units. In Figure 6-4, the point at which the peaking units supplement the output of the base load units has been nominally indicated as 50 percent of the maximum heat demand. However an economic optimization based on the specific heat load duration curve for the system must be performed to accurately determine the best number and sizes of base load and peaking units.

As noted in Section 611, in order to alleviate the capital cost of the DH system, it is quite common (especially in Europe) to build the heating station in stages. Typically, a small mobile heating unit burning high grade fuel (gas or oil) may be installed to provide initial heating requirements. As the DH system is expanded, the base load units are added while the mobile units could be retained and used as peaking units.

In developing the heating station, consideration should also be given to the use of existing facilities. Power plants and institutional steam plants may be integrated into the DH system, thereby improving the economic feasibility, and perhaps improving the operating efficiency of the overall system.

In this section of the report, the types and combinations of systems available for use as district heating plants are discussed and include the following:

- hot water stations;
- cogeneration
    - steam turbine topping cycle,
    - gas turbine topping cycle,
    - combined cycle,
    - diesel engine topping cycle,
    - steam bottoming cycle;

- heat pump systems;
- waste heat recovery systems;
- retrofit of existing power plants;
- thermal storage.

This section also discusses use of emerging technologies including the following:

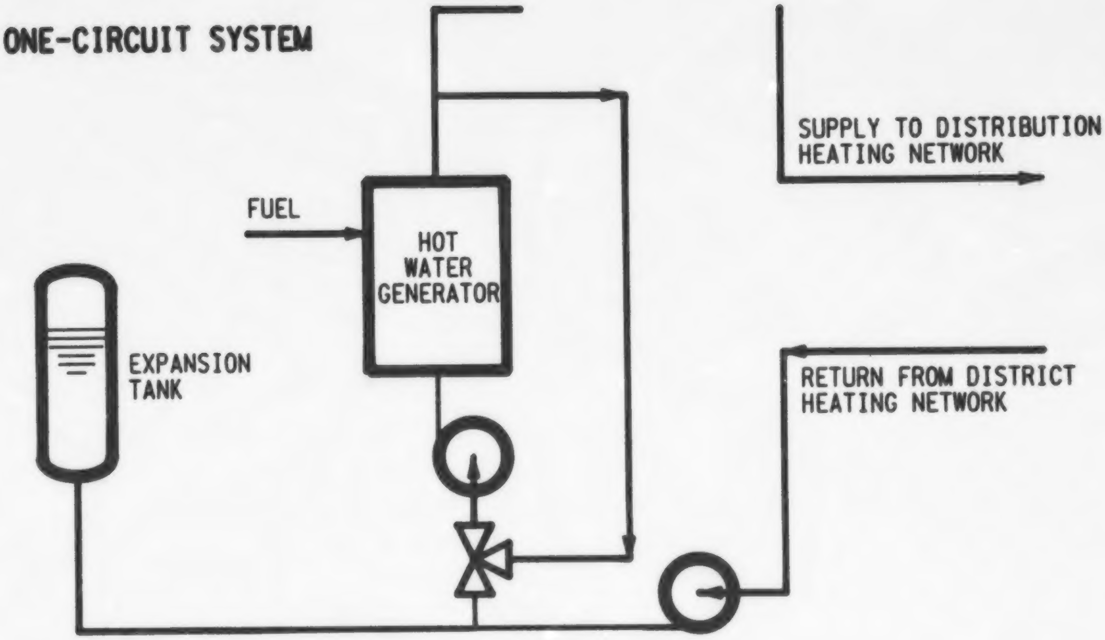
- advanced combustion technologies
  - fluidized bed combustion,
  - coal liquid mixtures,
  - coal gasification,
  - coal-fired gas turbines;
- fuel cell power plants.
- small nuclear reactors.

632 HOT WATER STATION

The simplest method of supplying heat to a DH network is by means of a hot water station in either a single circuit or two circuit system.

In the single circuit system the water is pressurized and heated to the required conditions and circulated around the DH network. In the two circuit system, steam (or hot water) is produced in a steam (or hot water) generator and then heats the DH network water through a heat exchanger (district heater). In recent years hot water generators have been more popular in Europe for economic reasons. The construction of steam and hot water generators is very similar as a steam drum is provided in the hot water generator to allow steam supply for heating requirements, sootblowers, etc. Typical configurations of one and two circuit systems are illustrated in Figure 6-5.

a) ONE-CIRCUIT SYSTEM


SUPPLY TO DISTRIBUTION HEATING NETWORK
FUEL
HOT WATER GENERATOR
EXPANSION TANK
RETURN FROM DISTRICT HEATING NETWORK

b) TWO-CIRCUIT SYSTEM

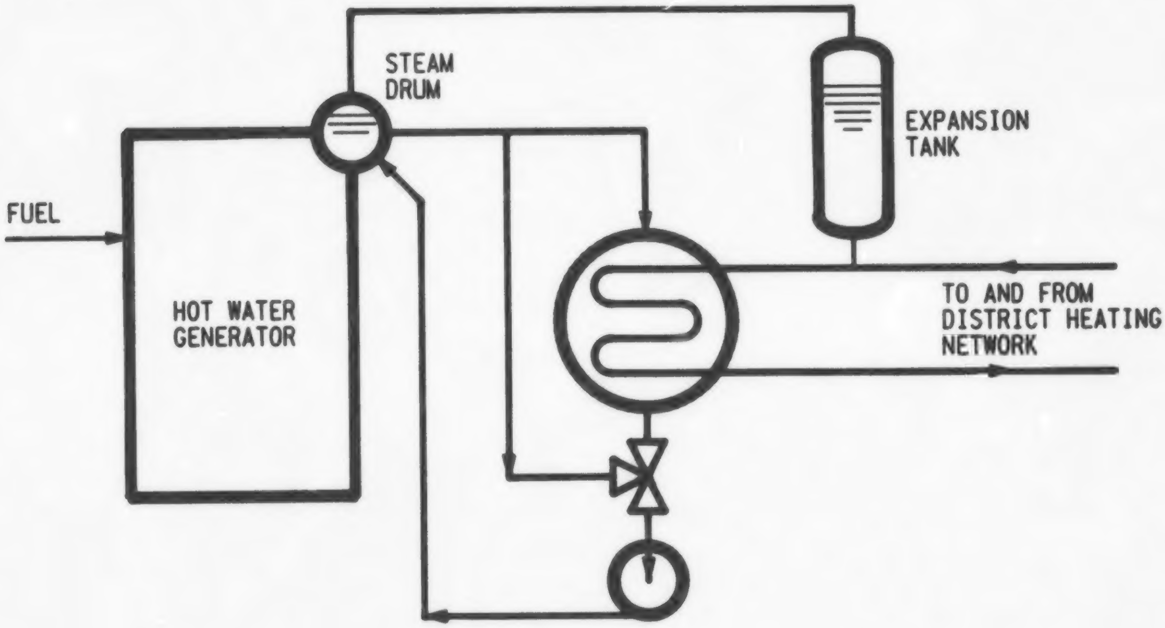

STEAM DRUM
EXPANSION TANK
FUEL
HOT WATER GENERATOR
TO AND FROM DISTRICT HEATING NETWORK

FIGURE 6-5
HOT WATER STATION

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J.A. Djarv of AB Energikonsult (62) reported the advantages of the two-circuit system as follows:

- The pressure and temperature in the steam generator can be selected independently of the DH network.
- A sufficiently high temperature in the steam generator can also be selected sufficiently high to avoid low-temperature corrosion when using low grade high sulphur fuels.
- Firing can be controlled on the basis of the steam pressure in the steam drum, which reacts more quickly to unbalance between the firing rate and the loading than is possible using water temperature control.
- The boiler circuit contains a relatively moderate amount of water and can therefore be taken up to the required operating temperature independently of the DH network.
- Steam can be taken from the steam drum for pressurizing the DH network, for deaeration of the feedwater, for fuel oil preheating (if required), and for sootblowing.
- Any contaminants in the DH network will not be admitted into the steam generator.

Both the one and two circuit systems can be designed for a wide range of boiler capacities, water/steam pressures and temperatures, and fuels. Typical fuels are oil, gas, coal, municipal wastes and, depending upon transportation distances, other lower bulk/energy density fuels such as biomass and peat.

Efficiencies of the hot water station could approach 90 percent (for a two-circuit system and boiler fitted with an economizer).

Due to their simplicity, hot water stations are economical. The two-circuit heating plant cost is usually approximately 15 percent higher than that of the one-circuit heating plant. Generally, the advantages of the two circuit system outweigh the higher cost. However, the cost of qualified operators required for steam generating plants must be taken into account by the economic analysis.

Figure 6-6 illustrates typical unit total capital costs ($/kW) of two circuit hot water stations burning various fuels. It should be noted that these costs are provided as an estimating guideline, to provide the reader with approximate total cost of central heating stations. The estimated costs are for single units installed in multi-unit stations. The indirect costs (engineering and construction management, owner's costs and interest during construction) were assumed to be 50% of the direct costs. Even though the Clean Air Act - Thermal Power Generating Emissions - National Guidelines for New Stationary Sources outline maximum NO_x, SO_2 and particulate emissions, no costs have been included for flue gas treatment equipment. Flue gas treatment systems have not as yet become standard installations in Canada and the cost of such systems is uncertain.

As an alternative to the two circuit system, the production of hot water or steam in a generator may be replaced by heating an organic fluid (oil) in a steam coil boiler at atmospheric pressure and circulating it through the district heaters to heat the DH network water. The advantage with this system is that it does not require the same number of operators as would be legally required for a steam or hot water station. Therefore, personnel costs are considerably reduced. The disadvantage with the system is that the oil to water energy conversion in the district heater is not as efficient as a steam/water system.

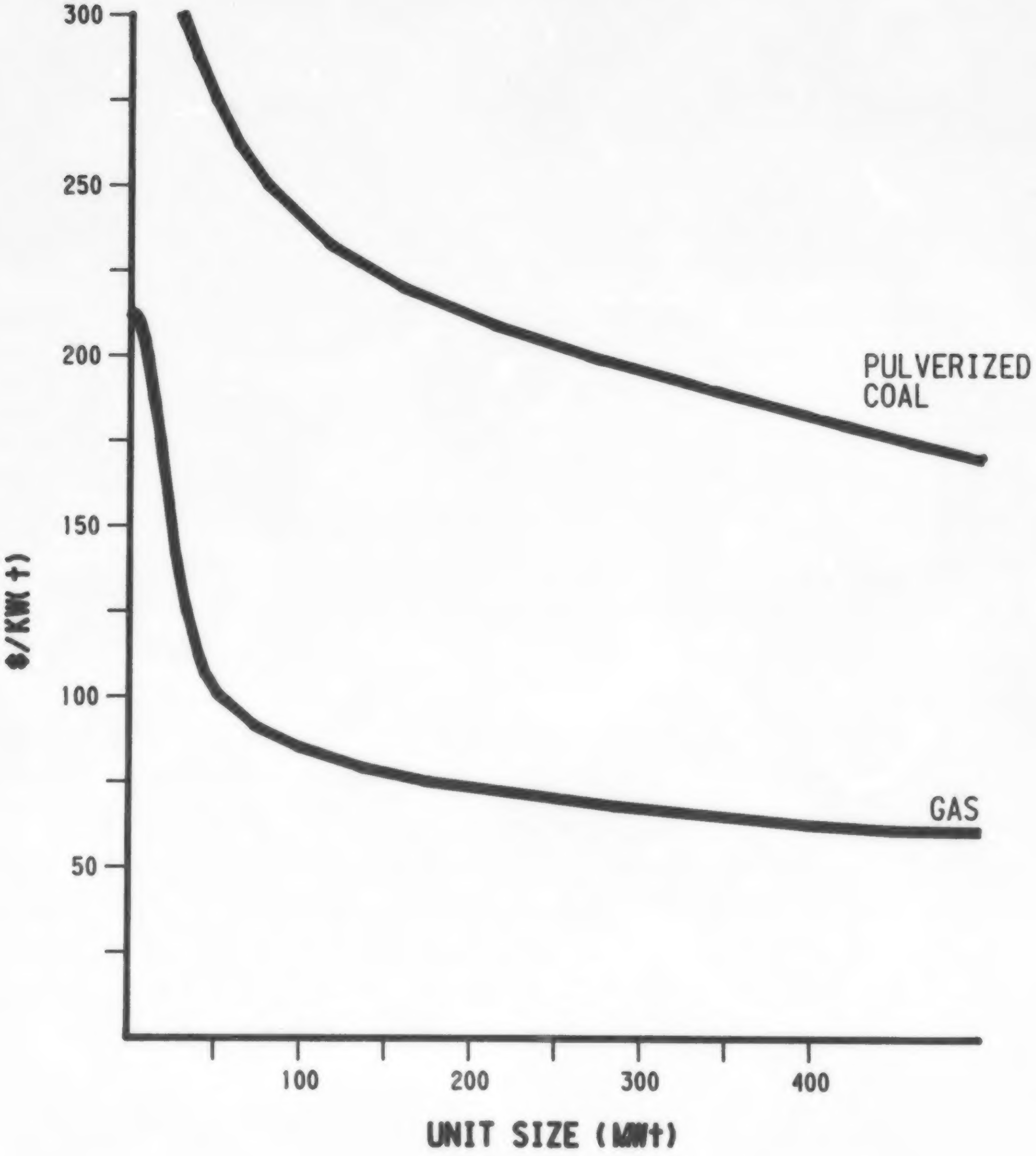

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FIGURE 6-6
TWO CIRCUIT HOT WATER STATION
ESTIMATED TOTAL CAPITAL COST

In Europe, the trend is to utilize two-circuit systems with steam or hot water generators when the DH system is in the preliminary phases of development and, as the heating requirement increases, to add combined heat and power units to the system.

.1 Hot Water Stations in Canada

Some of the DH studies for Canadian communities have demonstrated that hot water stations can be feasible alternatives for heat generation for hot water district heating systems. Development of these systems, however, has not progressed past the feasibility study stage.

These include studies for North Pickering, Ontario (16); a new small community similar in climatic conditions to North Pickering, Ontario (12); and for Tumbler Ridge, B.C. (52). Basic study criteria for each of these are outlined in Table 6-21.

In the North Pickering study, the use of high temperature water distribution and heating systems was discouraged since they are not considered to be compatible with future heat sources such as solar heat and heat pumps. Other systems evaluated in that study which produce low temperature hot water included cogeneration and nuclear base load heating with fossil fuel peak load heating. These types of systems are described later in this report.

Studies for Tumbler Ridge, B.C. investigated two types of coal-fired systems:

TABLE 6-21

Hot Water Stations

	North Pickering, Ontario (Population 70,000)	Tumbler Ridge, B.C. (Population 2,500)	Tumbler Ridge, B.C. (Population 2,500)	New Small Community Similar to North Pickering, Ontario (Population 2,500)	New Small Community Similar to North Pickering, Ontario (Population 10,000)	New Small Community Similar to North Pickering, Ontario (Population 20,000)
TYPE OF SYSTEM	Two Circuit System	Two Circuit System	Two Circuit System	Two Circuit System	Two Circuit System	Two Circuit System
District Heating Network - Supply Water Temperature	175°C	120°C	120°C	93°C	93°C	93°C
- Return Water Temperature	93°C	55°C	55°C	60°C	60°C	60°C
No. of Hot Water Stations to Supply Town	4	1	1	1	1	1
Boiler Ratings	Phase 1 - 3 boilers @ 29.3 MW_t Phases 2,3,4 2 boilers each @ 44 MW_t	2 boilers @ 5 MW_t 2 boilers @ 10 MW_t	2 boilers @ 5 MW_t 2 boilers @ 10 MW_t		4 boilers @ 112.9 x 10^6 kJ/hr	
Boiler Outlet Conditions	Hot Water	Organic Fluid (Oil) 300°C, atm.			107,000 lb/hr each	
Fuel	Heavy Fuel Oil, Natural Gas	80% Waste Coal 20% Marketable Coal (Fuel Oil or Propane as Standby)	80% Waste Coal 20% Marketable Coal (Fuel Oil or Propane as Standby)	Heavy Residual Oil	Heavy Residual Oil	Heavy Residual Oil
Capital Cost ($ '000)	PH. 1 $8,924 PH. 2, 3, 4 $7,003 per phase	$5,410 Hot Oil System	$8,416 Extension to Cogen.	$3,653	$8,687	$16,123

- a steam generating system to heat the DH system water with provision for retrofitting to generate electricity at a later date;

- a hot oil system to heat the DH system water.

The studies concluded that both schemes were economically feasible, however, the hot oil system was economically more attractive, based on a discounted cash flow analysis.

Each of the studies indicate that hot water stations are a feasible means of providing heat for a DH network, and should be one of the alternatives considered when evaluating heat sources, especially for initial stages of system development.

633 COGENERATION

Cogeneration is the simultaneous production of electricity and thermal energy (i.e. in the form of steam or hot water) from the same fuel source. Cogeneration can be an attractive source of heat for district heating as the overall efficiencies of the various types of systems are relatively high (60-90% as compared with 20-38% for electrical power generation alone and 75-92% for steam generation alone).

Cogeneration systems can be divided into two major groups, topping and bottoming cycles. In a topping cycle, fuel is burned to produce high-temperature heat which is expanded through a turbine to generate electrical or mechanical power. After passing through the turbine, the rejected heat is used in industrial applications as process heat. In a bottoming cycle, fuel is burned to produce process heat, with rejected heat used to generate either electrical or mechanical power.

Various types of cogeneration systems are discussed in the following sections.

.1 Steam Turbine Topping Cycle

The two types of steam turbine topping cycles which may be used to supply steam to heat the DH network water are the backpressure turbine system and the extraction (condensing tail) turbine system. The main difference between the two systems is that the ratio of steam/electrical generation is fixed for a backpressure turbine installation, whereas for an extraction steam system the amounts of steam extracted and electricity produced can be varied within equipment design limits.

The backpressure turbine system, which is commonly used in northern European countries, maximizes heat energy generation from non-condensing turbines. This alternative requires a lower capital investment than the extraction turbine system. To optimize capital cost, the size of the high pressure boiler and backpressure turbine combination is selected to permit high utilization (i.e. base load operation) of the equipment.

The extraction steam turbine system assigns a higher priority to augmenting the electrical generating capacity and a lower priority to economic benefits associated with optimizing heat energy generation. It uses automatic extraction condensing turbines with ratings designed to meet maximum heat demand. The system is popular in regions where heating loads are an adjunct to power generation or where there is not a good balance between heat and electrical requirements.

When considering the installation of a steam topping cogeneration cycle, the ideal turbine should meet the following requirements:

- Maximum cycle efficiency (the recovery of as much of the available fuel energy as possible in the form of heat or electricity).
- Maximum operating flexibility (the degree to which the electric generation and the heat output for DH water require independent control from each other).
- Minimum additional equipment and space requirements.
- No permanent loss of electric generation capacity.
- Lowest cost.
- Highest reliability.

The design of a steam turbine topping cycle is very site specific; however, the general cycle limits are as follows:

Size Range:	1 MW(e)
Fuel:	nuclear, oil, coal, wastes
Electricity-to-steam ratio:	47 - 80 kW/Gj
FCP (Fuel Consumed for Power Generation)	5300 kJ/kWhr
Backpressure (or extraction) steam pressure:	22 - 4000 kPa
Pollution:	SO_2, NO_x, particulates

Controls: Low sulphur fuel, flue gas scrubber, electrostatic precipitator

General System Notes: Efficient at part load

The backpressure and extraction steam turbine systems are discussed in detail in the following sections.

.2 Backpressure System

A typical schematic for a backpressure system is illustrated in Figure 6-7.

The high pressure steam produced by the steam generator drives the turbine-generator set to produce electricity, and the steam is exhausted from the turbine into the district heater at a pressure which provides a suitable temperature to heat the water circulating in the district heating network. As seen from Figure 6-7, an overall efficiency up to 82% can be attained in this cycle. The reason for such a high efficiency is that all of the condensed energy in the backpressure turbine is tranferred to the district heating water. (In contrast, all of the condensed energy from the low pressure section of standard condensing power plant is rejected to the environment via the condenser cooling water, resulting in efficiencies lower than 38%.)

For DH plants, the backpressure turbine maximum size limits are approximately 100 MWe and 250 MWt. As opposed to industrial backpressure turbine cogeneration systems which supply process steam in pressures up to 4000 kPa, turbines for district heating have backpressures in the range of 22-220 kPa. The district heaters utilize the latent heat in the steam discharged from the turbine to effect heating of the DH network water. The greater available enthalpy drop of steam in the turbine gives more backpressure power.

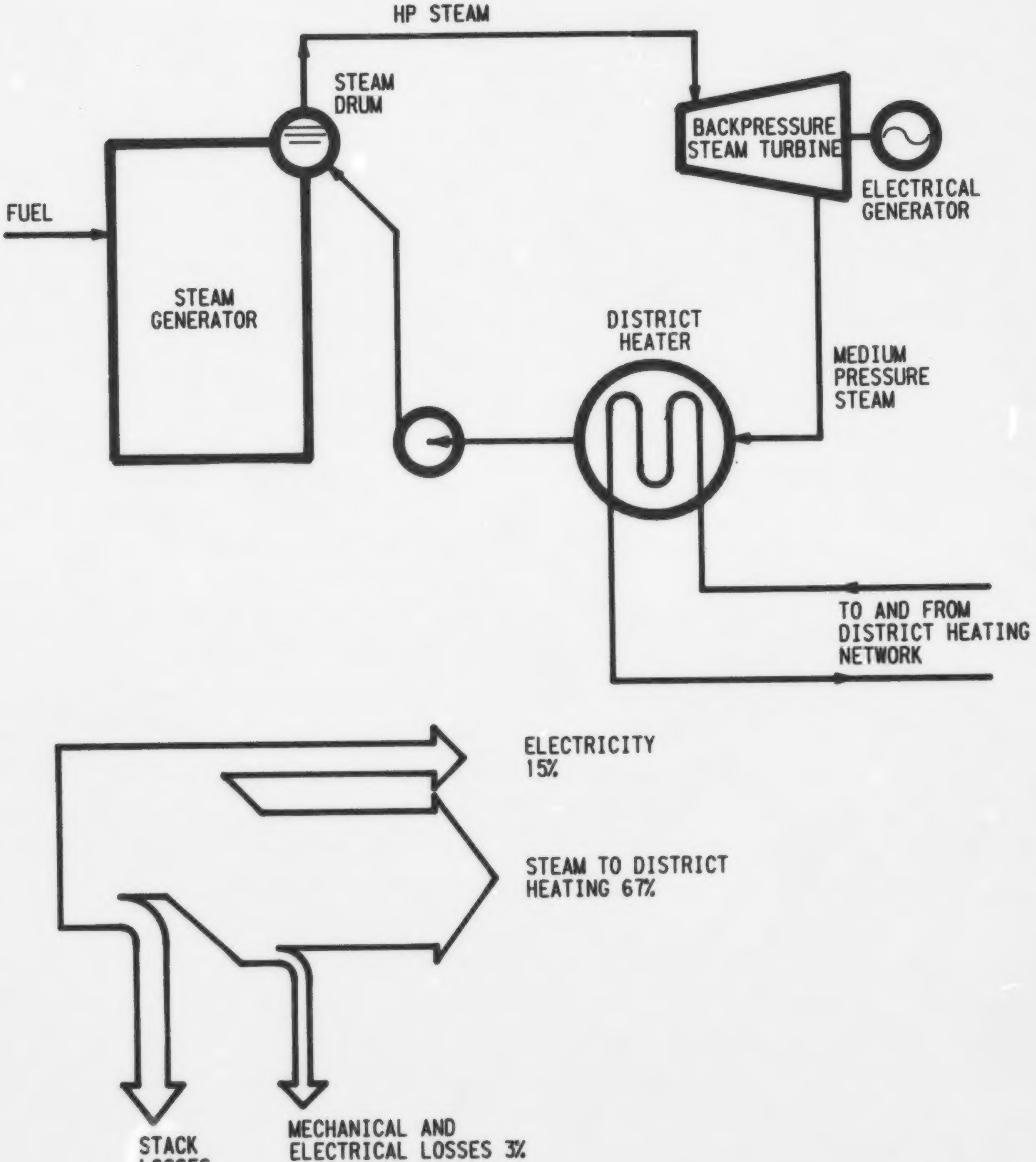
HP STEAM
STEAM DRUM
BACKPRESSURE STEAM TURBINE
ELECTRICAL GENERATOR
FUEL
STEAM GENERATOR
DISTRICT HEATER
MEDIUM PRESSURE STEAM
TO AND FROM DISTRICT HEATING NETWORK
ELECTRICITY 15%
STEAM TO DISTRICT HEATING 67%
STACK LOSSES 15%
MECHANICAL AND ELECTRICAL LOSSES 3%

FIGURE 6-7
BACKPRESSURE TURBINE SYSTEM

A higher turbine thermal efficiency with a given available enthalpy drop also gives more electricity with unchanged boiler output, and therefore correspondingly less heat. The electric power yield is thus affected by the turbine thermal efficiency and by the live steam data, the steam cycle (reheat or no reheat), the feedwater heating, and the pressure or the pressures at which the steam is taken out from the turbine.

The main disadvantage of the backpressure turbine is the fixed relationship between heat demand and electrical output. Since the district heating load sets the steam flow requirements into the district heater, the amount of steam exhausted by the turbine and the electricity produced are fixed by the heating load. As the electricity load does not necessarily fall in summer when the district heating load is greatly reduced, the backpressure system cannot be utilized to meet the electrical demand as the electric generation and the heat output for district heating cannot be adjusted independently. Therefore, the two operating limitations of the backpressure system are the permanent loss of electric generating capability and the limited operating flexibility.

Modifications to the system which would improve the operating flexibility (i.e. increase electrical generation during periods of low thermal load) include addition of an auxiliary condenser or the installation of a heat exchanger in the DH water circuit to reject part of the heat load to the environment. These modifications are not considered practical due to the added complication to the system, and the cost of electricity generated would not be as economical as electricity generated by a standard condensing turbine.

Figure 6-8 illustrates typical total unit capital costs ($/kW) for backpressure turbine systems. The horizontal axis provides the thermal output of the unit (MW). Typical electrical outputs at indicated thermal outputs are also indicated. As described for Figure 6-6, the costs are provided as an estimating guideline, to provide the reader with approximate total cost of the backpressure turbine system. The estimated costs are for single units installed in multi-unit stations. The indirect costs were assumed to be between 40 and 50 percent of the direct costs. No costs have been included for flue gas treatment equipment.

Backpressure turbines have been considered as viable options in a number of Canadian district heating studies including Chapleau (53) and North Pickering, Ontario (16). Pertinent data from these studies is presented in Table 6-22.

The study for Chapleau looked at two different cogeneration schemes: a backpressure system (as described in Table 6-22) and a combination backpressure/extraction turbine system. The study concluded that both schemes are economically viable, but the backpressure system showed a higher return on investment.

The study for Pickering North compared the backpressure turbine system against hot water stations and nuclear base load heating with fossil fuel peak load heating. The study showed that cogeneration was feasible, although, the hot water stations were found to be more economically advantageous. This is a reversal of traditional ranking, and the reason given for this situation is the unfavourable pricing of the by-product electricity.

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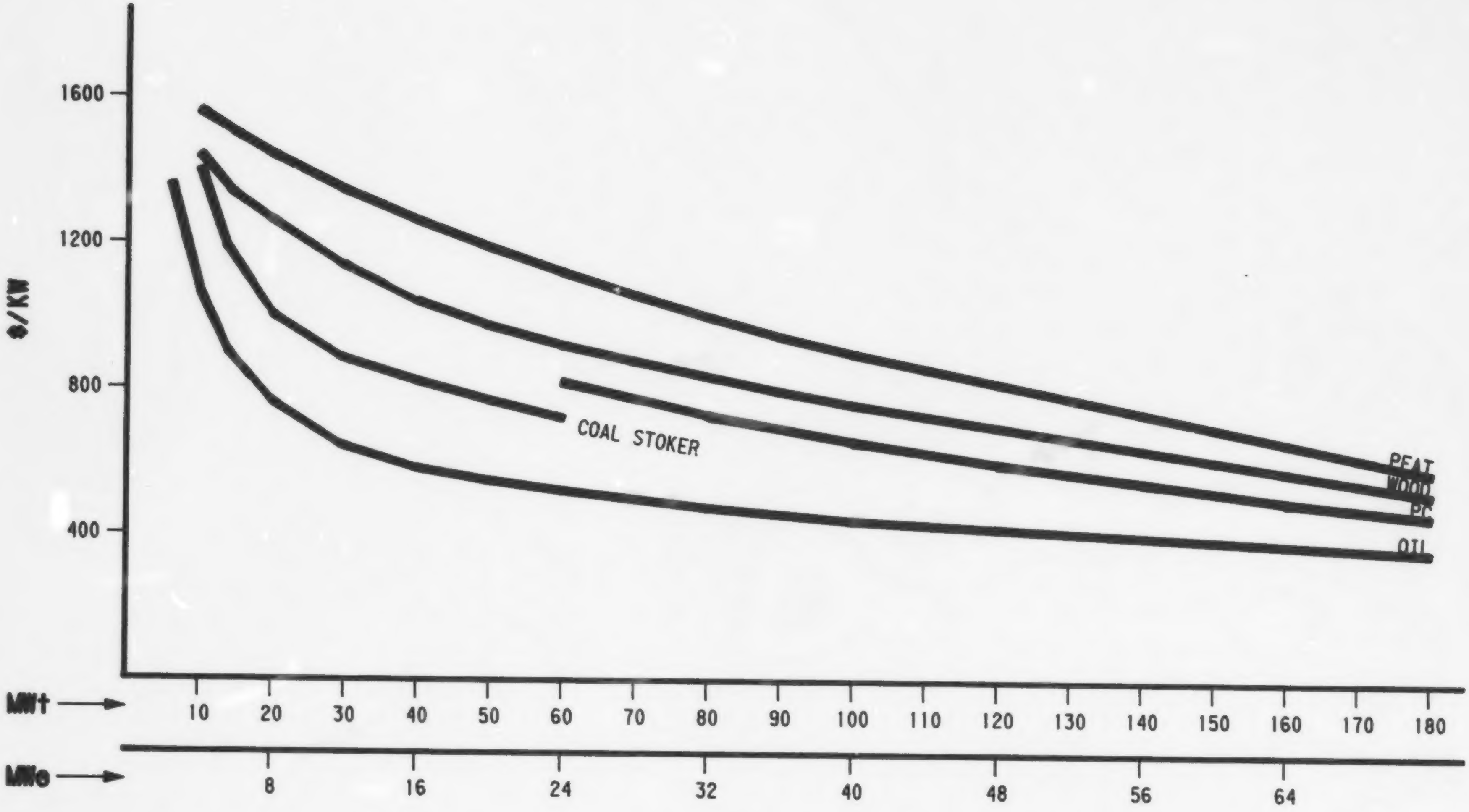


FIGURE 6-8
BACKPRESSURE TURBINE SYSTEM
ESTIMATED TOTAL CAPITAL COST

TABLE 6-22

Backpressure Turbine District Heating Systems

	CHAPLEAU Scheme C2	NORTH PICKERING, ONTARIO Scheme C2
District Heating Network - Supply Water Temperature - Return Water Temperature	 120/80°C 60°C	 100°C 60°C
Total Heat Output for District Heating	51.73 MWt	370 MWt
Process Steam Output	-	-
Total Electrical Output	10 MWe	138.1 MWe
Steam Generators	2 @ 21 MWth (9.9 kg/s, 56 bar, 480°C) 1 @ 15 MWth (4.78 kg/s, 2.7 bar)	2 @ 86.6 kg/s, 10960 kPa, 496°C
Auxiliary Hot Water Generators	2 @ 13 MWth (120°C)	(separate peaking boiler plants)
Backpressure Turbines	2 @ 5 MWe, 8.93 MWth Throttle Steam: 9.9 kg/s, 56 bar Backpressure Steam: 2.7 bar	1 @ 64.5 MWe, 185 MWt 1 @ 73.6 MWe, 185 MWt Throttle Steam: 86.6 kg/s, 10960 kPa, 496°C Backpressure Steam: 1 @ 126 kPa, 1 @ 66 kPa
Fuel	Biomass	Fossil Fuel
Thermal Cycle Efficiency Overall Efficiency	81% 61% (using wet biomass)	
Capital Cost ($ '000)	$20,500	$109,700

.3 Extraction Steam System

A typical schematic for an extraction steam system is illustrated in Figure 6-9.

The high pressure steam produced by the boiler drives the turbine-generator set to produce electricity. However, some of the steam is extracted from the turbine at an intermediate stage for heating the water of the district heating system.

As for the backpressure turbine systems, extraction steam turbines are generally designed for base load heat production and peaking boilers are provided to augment heat supply during peak heat load periods. However, unlike backpressure turbine systems, as the heat load falls the electricity production from an extraction turbine system increases, since less steam is extracted for heating. Therefore, the extraction steam turbine must be designed not only to follow the district heating base load characteristics, but also to operate in a pure condensing (power-only) mode. The turbine should provide economical operation throughout the year in both the district heating and the power only mode. The maximum combined electric and heat generation efficiency is achieved when the turbine is designed to match the heat consumption.

A detailed description of the design features of an extraction turbine for district heating is beyond the scope of this study, however, the specific features of the turbines may be summarized as follows (Synergic Resources Ltd., EPRI EM-2695 Vol. 2, DE8390075):

- Suitable openings in the turbine cylinders for extraction of large amounts of low pressure steam.

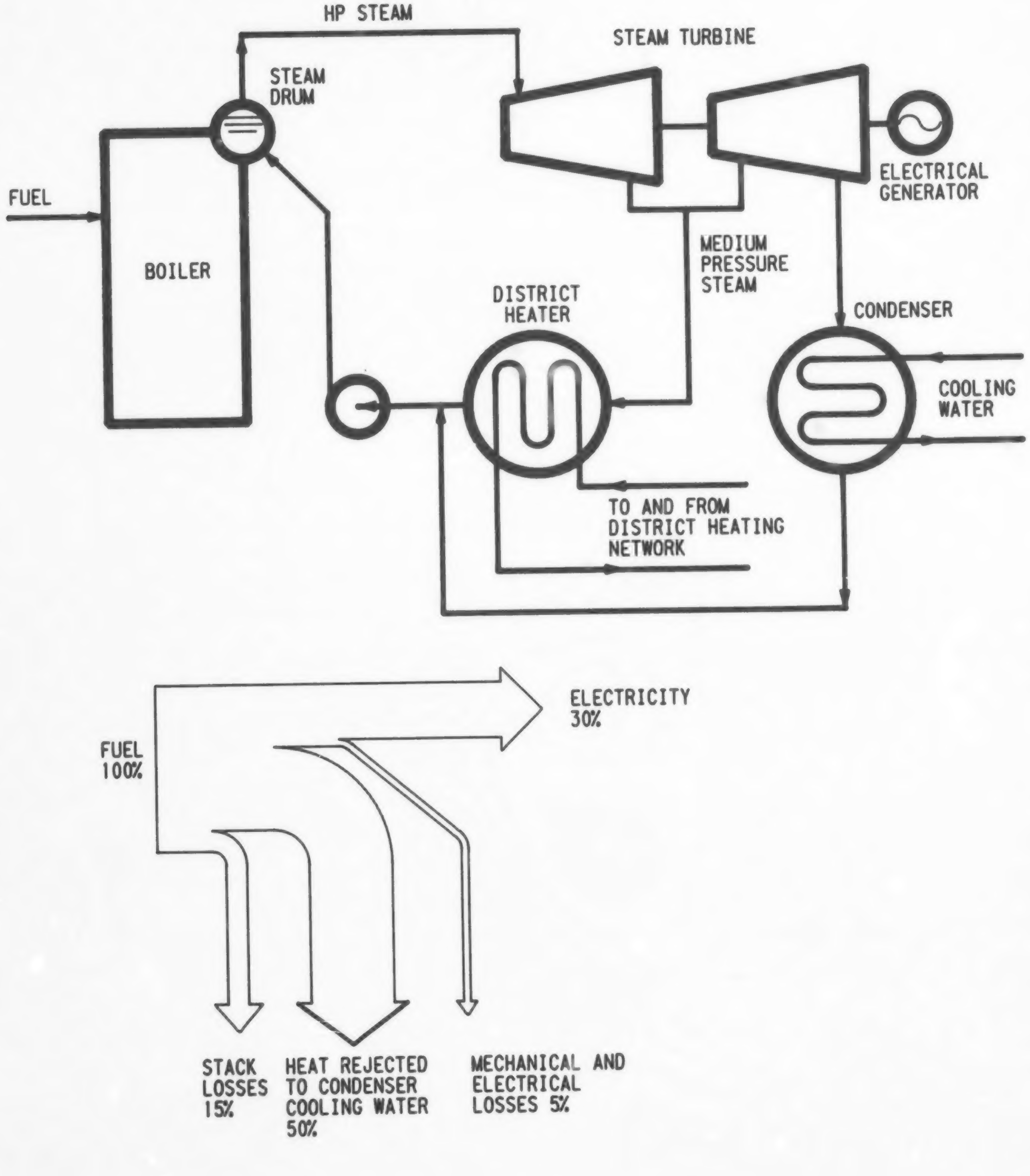

HP STEAM
STEAM TURBINE
STEAM DRUM
FUEL
BOILER
ELECTRICAL GENERATOR
MEDIUM PRESSURE STEAM
DISTRICT HEATER
CONDENSER
COOLING WATER
TO AND FROM DISTRICT HEATING NETWORK
ELECTRICITY 30%
FUEL 100%
STACK LOSSES 15%
HEAT REJECTED TO CONDENSER COOLING WATER 50%
MECHANICAL AND ELECTRICAL LOSSES 5%

FIGURE 6-9
EXTRACTION STEAM TURBINE SYSTEM

- Capability to control, concurrently and independently, electrical load and the steam extraction over a wide range of load demands.

- Capability to operate in the condensing mode.

- Heating of the district water in series extraction heat exchangers.

- Minimum throttling of extraction steam to ensure optimal operation of the bleed system over a wide range of parameters.

In recent years condensing tail turbines have been considered in many North American studies. In 1982, Oak Ridge National Laboratory (80) evaluated 200 and 400 MW(e) coal-fired cogeneration plants for the Minneapolis-St. Paul District Heating System. The following tables and figures excerpted from this study illustrate the key plant parameters, the net turbine heat rate and the net plant heat rates.

TABLE 6-23

Key Plant Parameters of Coal-Fired, Cogeneration Plants with Steam Turbines

Parameter	200 MW(e)-350 MW(t)	400 MW(e)-700 MW(t)
Turbine configuration	Tandem-compound, two-flow, with 28-in. last-stage blades	Tandem-compound, four-flow, with 28-in. last-stage blades
Steam flow at high-pressure turbine inlet, (guaranteed), 10^6 lb/h	1.72	3.44
Steam pressure at high-pressure turbine inlet (guaranteed), psia	2,414.2	2,414.2
Steam temperature at high-pressure turbine inlet (guaranteed), °F	1,000	1,000
Turbine back pressure, in. Hg[a]	3	3
Turbine output, MW(e)		
Power-only mode	257[a]	514[a]
Cogeneration mode	200[b]	400[c]
Auxiliary power (power-only mode), MW(e)	22[d]	44[d]
Station output (power-only mode), MW(e)	235	470
Number of feedwater heating stages	6	6
Generator rating, MVA	285	570
Stages of district heating	2	2
District heating supply/return temperatures, °F/°F	270/150	270/150
Design district heating system flow, lb/h	9,698,000	19,396,000

TABLE 6-23 (Cont'd)

Key Plant Parameters of Coal-Fired, Cogeneration Plants with Steam Turbines

Parameter	200 MW(e)-350 MW(t)	400 MW(e)-700 MW(t)
Station heat rate,[e] Btu/kWh		
Power-only mode	10,175	10,175
Cogeneration mode	6,873	6,873
Station thermal efficiency (power-only mode), [e] %	33.5	33.5
Steam generator	Subcritical pressure, single reheat with a balanced-draft furnace	Subcritical pressure, single reheat with a balanced-draft furnace
Steam flow, maximum continuous rating, 10^6 lb/h	1.9	3.8
Steam pressure at superheater outlet, psig	2,640	2,640
Steam temperature, °F		
Superheater outlet	1,010	1,010
Reheater outlet	1,005	1,005
Final feedwater temperature, °F	475.8	475.8
Fuel type	Western, subbituminous coal	Western, subbituminous coal

[a] Includes boiler feed pump.
[b] At 342 MW(t).
[c] At 684 MW(t).
[d] Assumed to be 8.6%.
[e] Based upon same auxiliary power requirements for pulverized-coal and atmospheric fluidized-bed and a boiler efficiency of 86%.

Source: Oak Ridge National Laboratory (ORNL/TM-6830/P8)

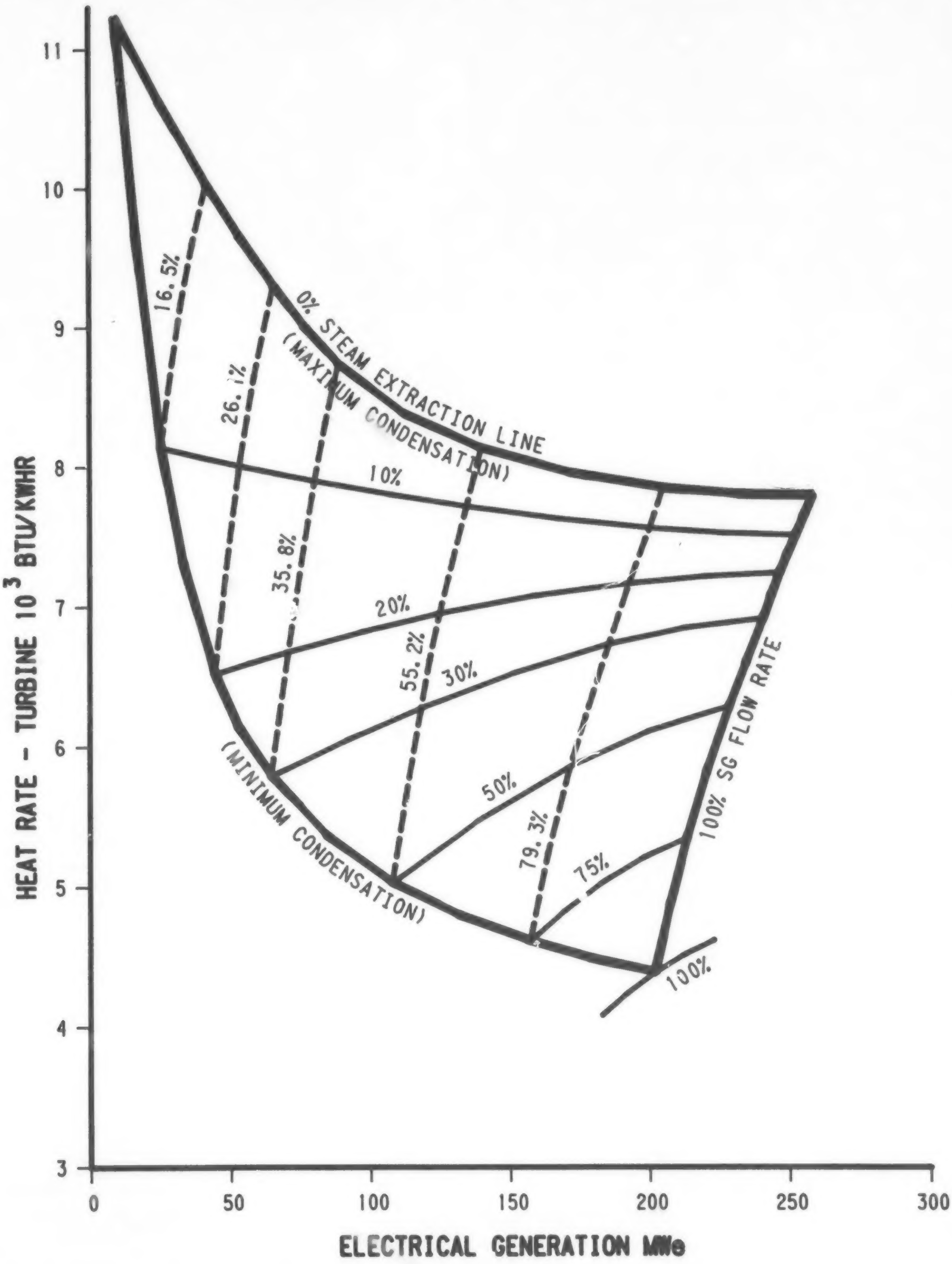


FIGURE 6-10
NET TURBINE HEAT RATE FOR A COGENERATION
STEAM TURBINE WITH DOUBLE EXTRACTION
AND MAXIMUM LOAD OF 342.4 MW(t)

SOURCE: OAK RIDGE NATIONAL LABORATORY
(ORNL/TM-6830/P8)

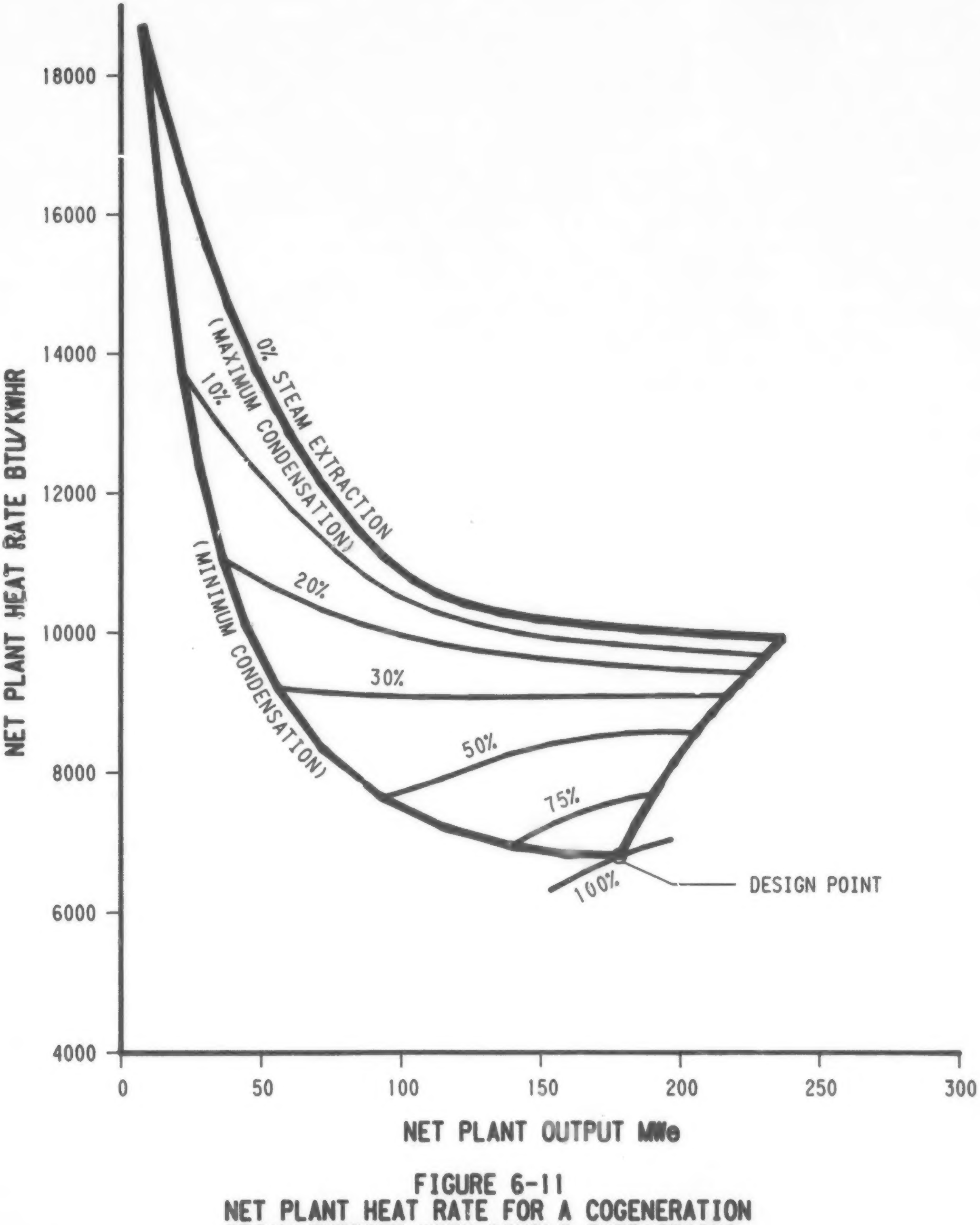


FIGURE 6-11
NET PLANT HEAT RATE FOR A COGENERATION STEAM TURBINE WITH DOUBLE EXTRACTIONS AND MAXIMUM LOAD OF 342.4 MW(t)

SOURCE: OAK RIDGE NATIONAL LABORATORY
(ORNL/TM-6830/P8)

TABLE 6-24

Net Plant Heat Rates for a Plant Equipped with 200 MW(e)-350 MW(t) Cogeneration/District Heating Turbine and Pulverized-Coal or Atmospheric Fluidized-Bed Boiler in Btu/kWh[a]

Net Plant Output [MW(e)]	Plant Heat Output/Load						
	0 MW(t)	34.2 MW(t)	68.4 MW(t)	102.6 MW(t)	171.0 MW(t)	256.5 MW(t)	342.4 MW(t)
23.6	17,000	14,072					
37.8	15,100	13,200	11,277				
55.9	13,350	12,100	10,800	9,393			
94.4	11,380	10,980	10,250	9,390	7,761		
141.5	10,480	10,220	9,880	9,386	8,400	7,024	
177.0	10,270	10,000	9,760	9,382	8,680	7,700	6,873
190.9	10,220	9,990	9,720	9,381	8,755	7,900	
205.4	10,196	9,960	9,700	9,380	8,763		
216.8	10,188	9,950	9,670	9,379			
222.5	10,184	9,943	9,663				
228.2	10,180	9,933					
235.0	10,175						

[a] These net plant heat rates also apply for larger plant equipped with the 400 MW(e) - 700 MW(t) cogeneration turbine; in that case, the heat rates corresponds to twice the values indicated for the power and heat output.

Source: Oak Ridge National Laboratory (ORNL/TM-6830/P8) (80).

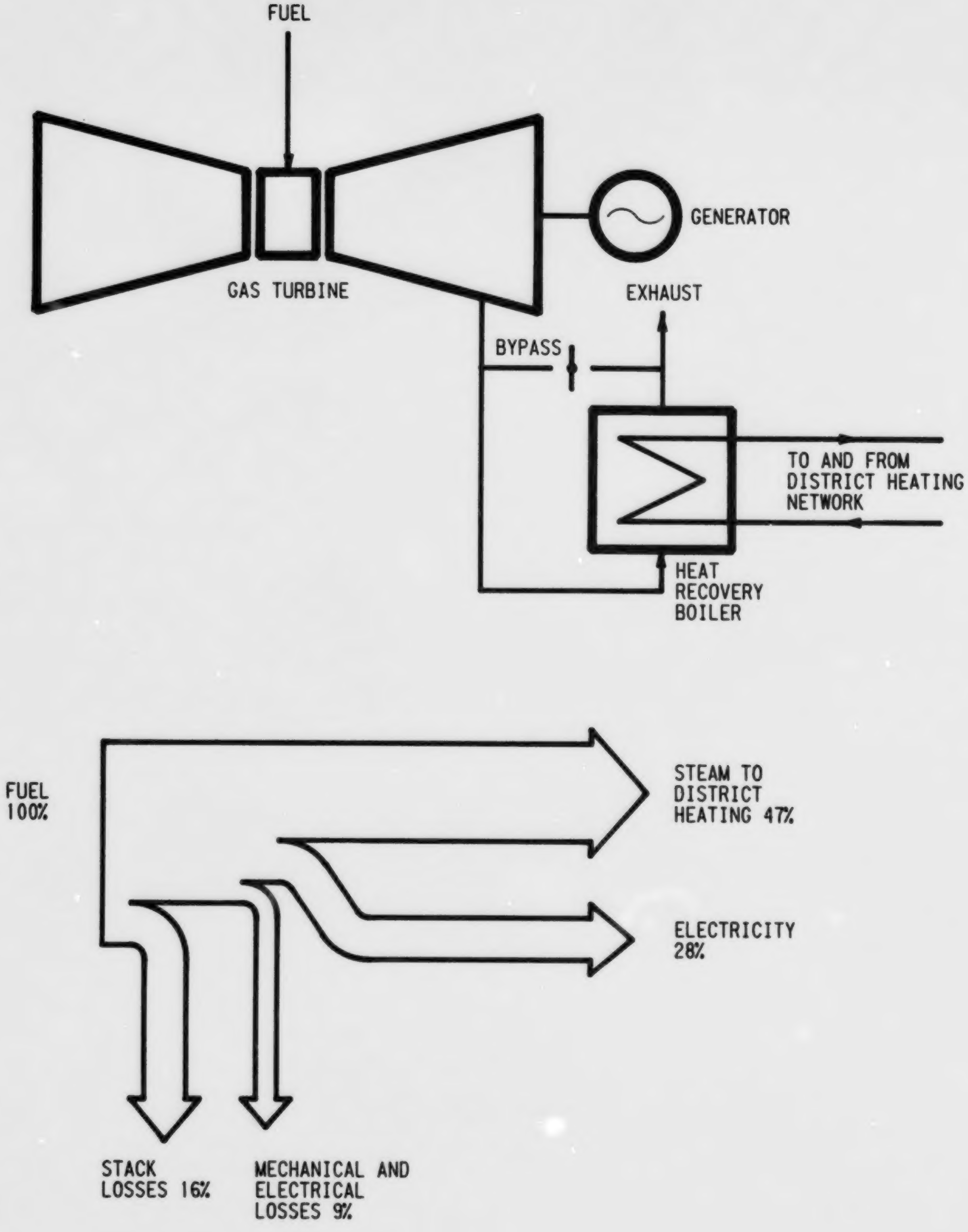

FUEL
GAS TURBINE
GENERATOR
EXHAUST
BYPASS
TO AND FROM DISTRICT HEATING NETWORK
HEAT RECOVERY BOILER
FUEL 100%
STEAM TO DISTRICT HEATING 47%
ELECTRICITY 28%
STACK LOSSES 16%
MECHANICAL AND ELECTRICAL LOSSES 9%

FIGURE 6-12
GAS TURBINE TOPPING CYCLE

.4 Gas Turbine Topping Cycle

In the gas turbine topping cycle, fuel is burned in the combustion chamber and the resultant hot gases turn the power turbine which drives the generator to produce electricity. The exhaust gas from the turbine is then used as a heat source for the district heating system water by means of heat recovery. A typical schematic for the system is illustrated in Figure 6-12.

The design of a gas turbine topping cycle is very site specific, however, the general cycle parameters are as follows:

Size range:	0.5 - 75 MW(e)
Efficiency:	approx. 70% - 80% (based on HHV of fuel); up to 90% for very clean fuels (based on LHV)
Fuels:	gas, No. 2 oil, crude oil, treated residual, SNG (low BTU)
Electricity-to-steam ratio:	210 - 230 kW/Gj
FCP (Fuel Consumed for Power Generation)	5800 - 5900 kJ/kWhr
Process steam pressure	1035 - 4140 kPag
General System Notes:	the 538°C exhaust gas from the gas turbine can be used as clean hot gas

Although gas turbines are available in small sizes (less than 1 MW), these are relatively expensive per kW of capacity. Only starting at the 9-10 MW range do gas turbines make sense for cogeneration.

A gas turbine topping system is favoured where power requirements are greater than those for process steam. Reducing the pressure ratio at a constant inlet temperature can increase operational flexibility and efficiency by lowering the power-to-steam ratio.

An advantage of the system is that power can be produced independently of the heating demand, using a bypass arrangement on the gas turbine exhaust side. Other advantages of the system include low capital cost, short construction/installation time, and system design for fully automatic operation.

Figure 6-13 illustrates typical total unit capital costs ($/kW) for gas turbine topping systems. The horizontal axis indicates the thermal output of the unit (MW). Typical electrical outputs at indicated thermal loads are also indicated. The costs are provided as an estimating guideline to provide the reader with approximate total cost of the gas turbine topping system. The estimated costs are for single units installed in multi-unit stations. The indirect costs are assumed to be typically thirty percent of the direct costs.

The major disadvantage with the system is that gas turbines are sensitive to fuel quality , so that running on inferior grades of fuel results in high operating costs. Poor fuel economy at low electrical loads in a disadvantage of the gas turbine. The environmental impacts, however, are considerably less severe than from other conventional thermal utility power station plants, due to reduced air pollution and the fact that no cooling water is required.

The burning of lower grade fuels, including coal in gas turbines is under continuing development and these methods are discussed further in Section 638 of the report.

In Canada, land based gas turbines are generally used for electrical peak electricity load requirements and therefore see limited annual hours of operation. However, when designing a combined heat and power DH facility, the feasibility of a gas turbine topping cycle should be considered, especially if high grade fuel is readily available and environmental impact is a concern.

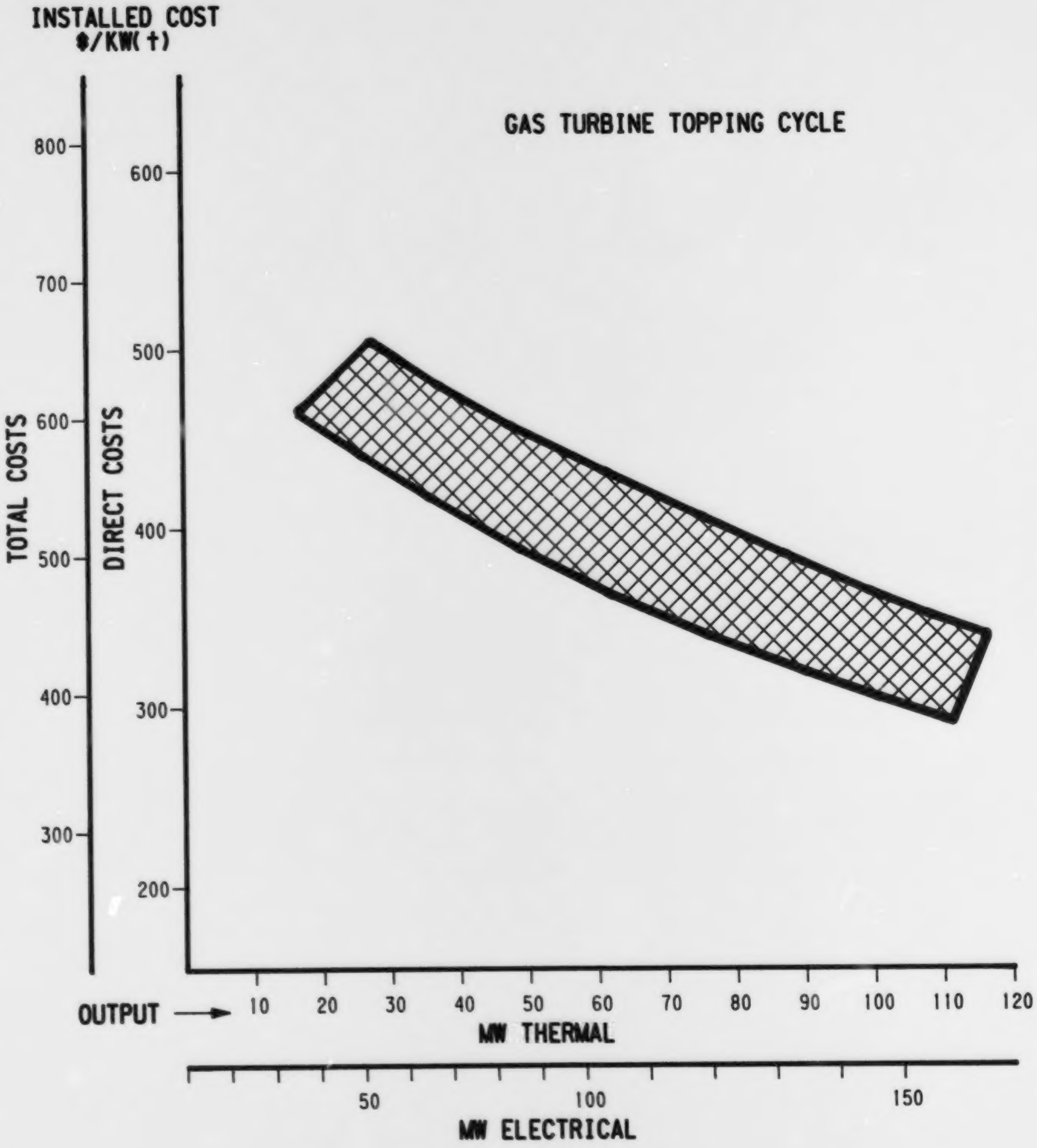


FIGURE 6-13
GAS TURBINE TOPPING CYCLE
ESTIMATED TOTAL UNIT CAPITAL COST

In Europe, gas turbine topping cycles are used in DH systems. For example, the Lappeenrannan Lampovoima Oy (Lavo) plant in Finland consists of two completely independent power blocks, each with its own control room, which are connected in parallel into the electric power and DH systems. Block 1 is a gas turbine topping cycle with outputs of 33.7 MW(e) and 47 MW(t). When Block 2 of the plant was installed, combined cycles were provided. In this plant, the use of a gas turbine topping cycle was found to be feasible for the initial unit to meet the district heating requirements, and, when the system expanded, more advanced cycles were added to supplement heat production.

.5 Gas Turbine Combined Cogeneration Topping Cycle

The gas turbine combined cogeneration topping cycle (commonly referred to as the combined cycle) is achieved by combining the gas turbine and steam topping cycles. Electricity is provided by electric generators connected to both the gas and steam turbines. A typical schematic for the system is shown in Figure 6-14.

The design of a combined cycle is very site specific, although general cycle parameters are as follows:

Size range: 1 - 150 MW(e)

Fuels: gas, No. 2 oil, treated residual, SNG (low BTU)

Electricity-to-steam ratio: 160 kW/Gj

FCP (Fuel Consumed for Power Generation) 5300 kJ/kWhr

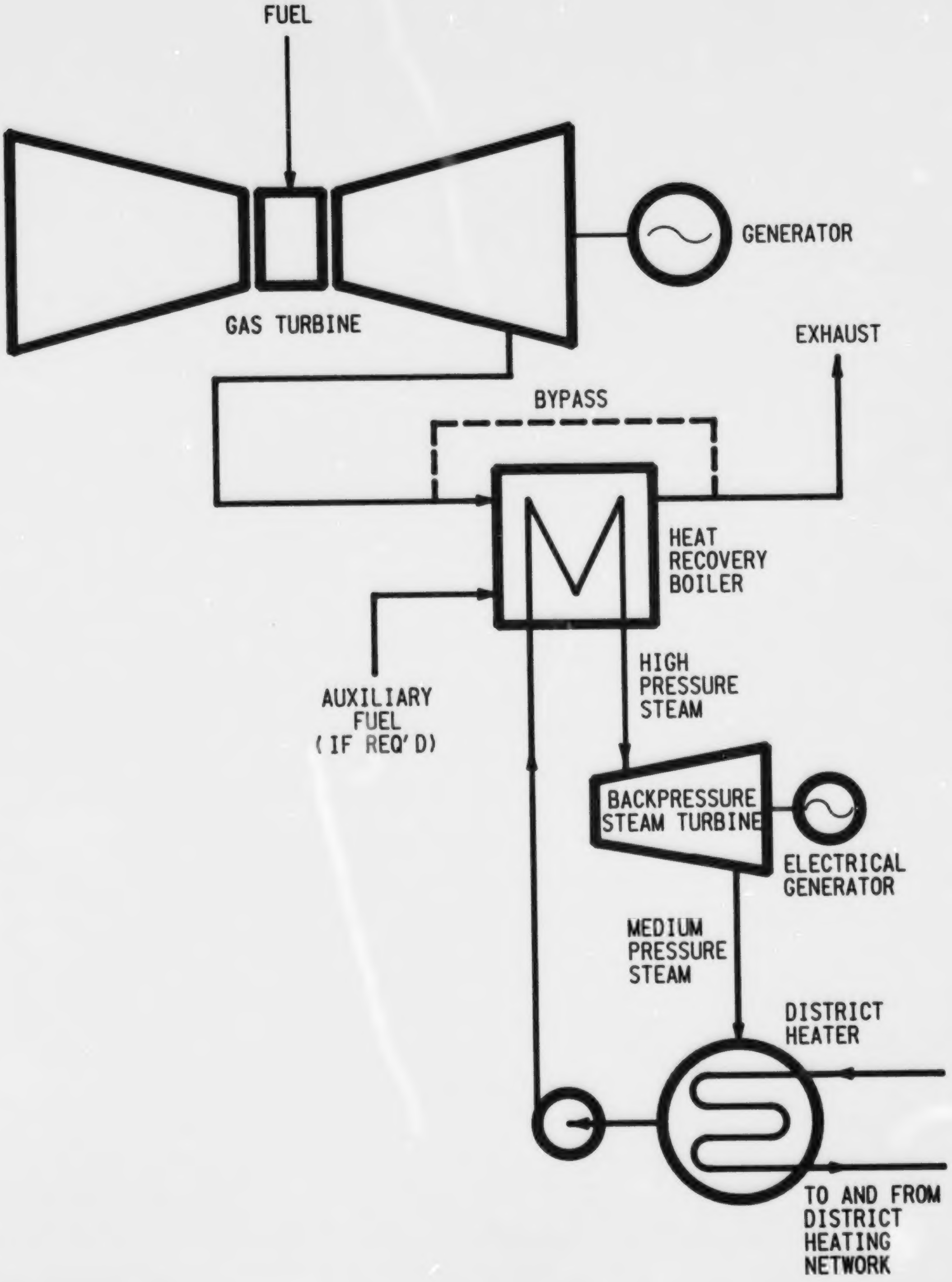

FUEL
GAS TURBINE
GENERATOR
EXHAUST
BYPASS
HEAT RECOVERY BOILER
AUXILIARY FUEL (IF REQ'D)
HIGH PRESSURE STEAM
BACKPRESSURE STEAM TURBINE
ELECTRICAL GENERATOR
MEDIUM PRESSURE STEAM
DISTRICT HEATER
TO AND FROM DISTRICT HEATING NETWORK

FIGURE 6-14
GAS TURBINE COMBINED
COGENERATION TOPPING CYCLE

Process steam pressure	105 - 6205 kPag
General System Notes:	variable power/steam ratio backpressure steam turbine

As in the gas turbine topping cycle, the fuel is burned in the combustion chamber of the gas turbine and the gases are expanded in the power turbine section to drive a generator to produce electricity. The heat is then recovered from the hot exhaust gases in the heat recovery boiler. In the combined cycle, the steam produced in the heat recovery boiler is expanded through a steam turbine to produce further electricity. The steam turbine could be of the backpressure or extraction type. Depending on the amount of steam required, additional fuel could be burned in the heat recovery boiler. The system is very flexible regarding the amounts of electricity and process heat produced, and a cycle optimization analysis should be performed for each specific installation.

The advantages of the combined cycle are low capital costs, low heat rate, and short construction/installation times. The disadvantage is that lower quality fuel dramatically increase operating costs of the gas turbine (additional fuel for the heat recovery boiler can be of lower grade). The combined cycle, however, has less environmental impact than other conventional utility thermal power station plants with respect to air quality and cooling water requirement.

Figure 6-15 illustrates typical total unit capital costs ($/kW) for combined cycles. The horizontal axis indicates the thermal output of the unit (MW). Typical electrical outputs at indicated thermal loads are also indicated. The costs are provided as an estimating guideline to provide the reader with approximate total cost of a combined cycle system. The estimated costs are for single combinations installed in multi-combination stations. Each combination consists of a gas turbine, heat recovery boiler and steam turbine.

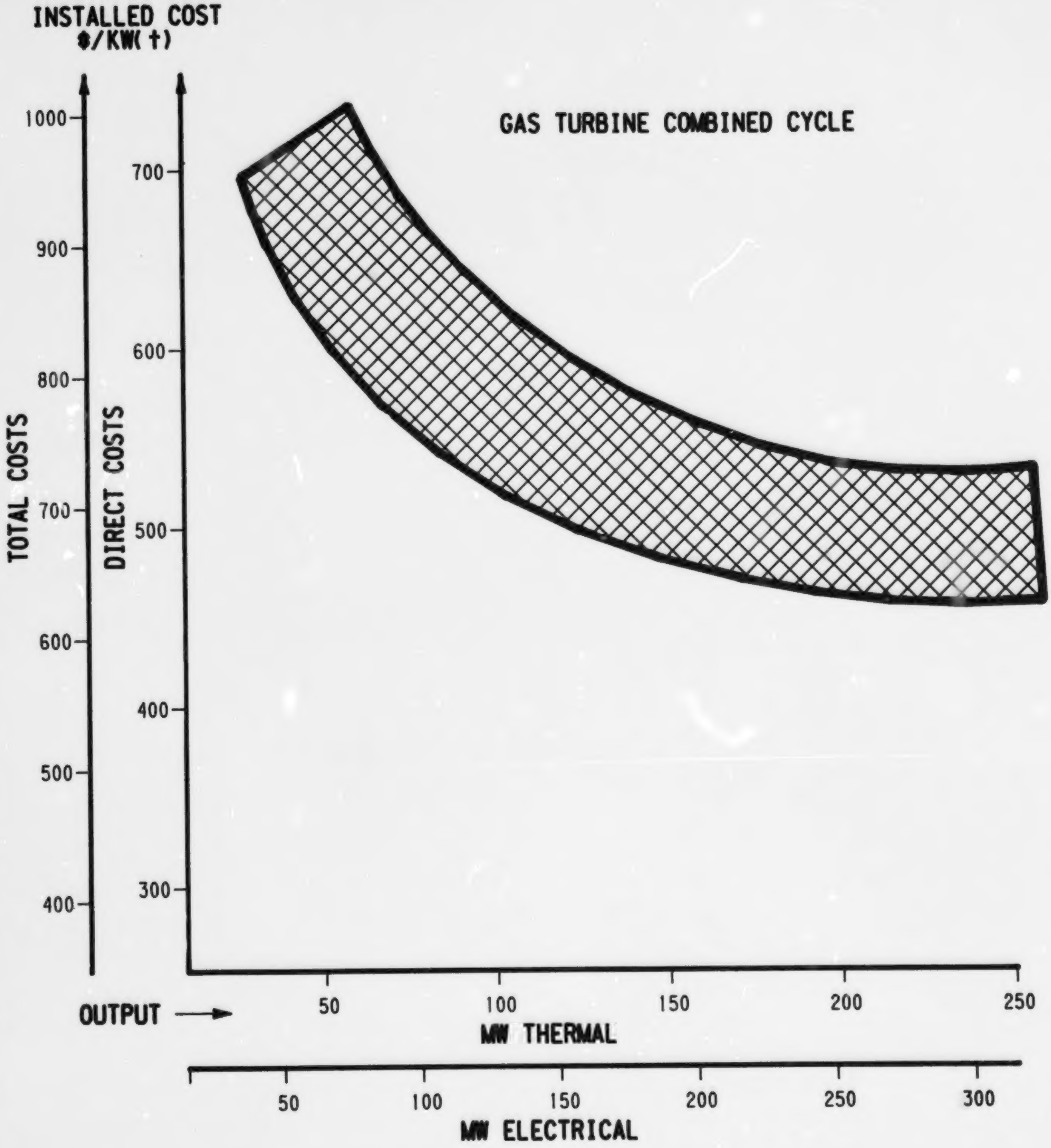


FIGURE 6-15
GAS TURBINE COMBINED CYCLE
ESTIMATED TOTAL UNIT CAPITAL COST

The possibility of gauging more than one gas turbine with a single steam turbine should be reviewed for savings in capital cost. The indirect costs were assumed to be typically thirty percent of the direct costs.

In 1977, a report entitled "Gas Turbines and District Heating - Research Report No. 10" was prepared for the Office of Energy Conservation (EMR, Ottawa) by Acres Shawinigan Ltd. This study evaluated the feasibility of providing a small community of 70,000 people (similar to North Pickering, Ontario) with heat and electricity by means of various combinations of gas turbine generators with heat recovery equipment and auxiliary boilers. Gas turbine topping and combined cycles were evaluated in the study.

The study concluded that all of the gas turbine based schemes are feasible, can operate with overall annual cycle efficiencies in excess of 70 percent and would provide a reliable source of electrical and heat energy. The study makes the following two recommendations:

1. For any planned new community, due consideration should be given to the provision of district heating in combination with electrical power generation. If the proposed community is not within economical heat transportation distance, then the schemes outlined in this study should be considered with the European practice of utilizing coal, solid waste material, oil or gas fired boilers and steam turbine generators to provide both heat and electrical energy.

2. Continuing attention should be paid to improvements in gas turbine technology and, in particular, developments in the utilization of coal derived fuels, with a view to further enhancement of the attractiveness of gas turbine based district heating/electrical power generating schemes.

.6 Diesel Engine Topping Cycle

A diesel engine topping cycle is similar to a gas turbine topping cycle, except that a diesel engine has a water cooling circuit which is another source for heat extraction in addition to the exhaust gases. A typical schematic of the system is illustrated in Figure 6-16, and the general cycle parameters are as follows:

Size range:	0.5 - 35 MW(e)
Thermal Efficiency:	70 - 80% (based on HHV of fuel) up to 90% (based on LHV of fuel)
Fuels:	gas, No. 2 oil, crude oil, residual oil
Electricity-to-steam ratio:	380 kW/Gj
FCP (Fuel Consumed for Power Generation)	6330 - 7385 kJ/kWhr
Process steam pressure	105 - 1050 kPag

Diesel engines produce most of their thermal energy in the form of hot water at 80-95°C, and not as steam. Steam can be produced in an ebullient type of heat recovery boiler at a maximum pressure of 210 kPag. Only about 15-20% of the fuel input can be recovered as steam at 1050 kPag.

Due to the high ratio of electricity to heat produced in a diesel engine topping cycle (higher than that of the steam or gas turbine cycles), the diesel is most advantageously applied in situations where there is a low heat demand and a relatively high electric power demand.

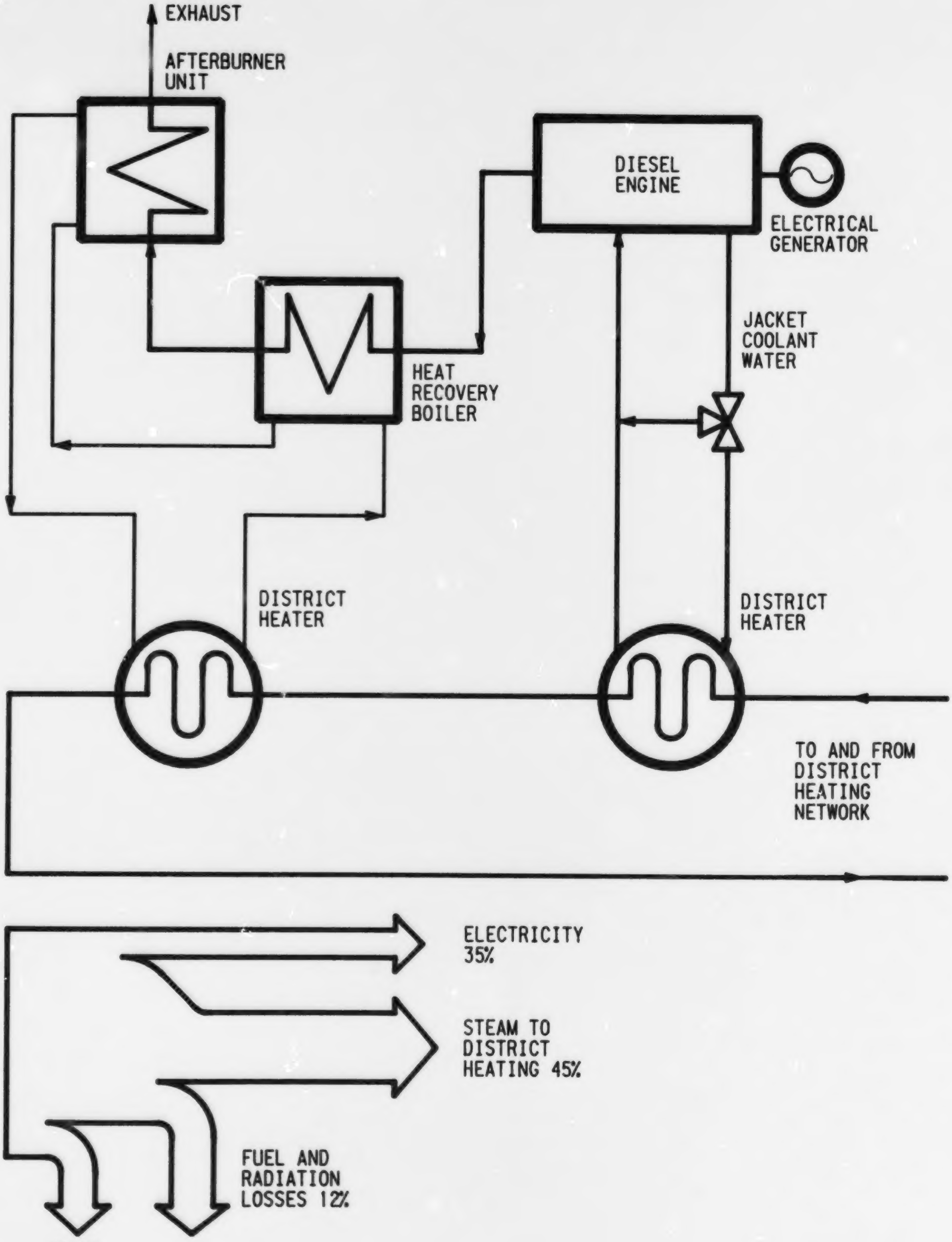

EXHAUST
AFTERBURNER UNIT
DIESEL ENGINE
ELECTRICAL GENERATOR
JACKET COOLANT WATER
HEAT RECOVERY BOILER
DISTRICT HEATER
DISTRICT HEATER
TO AND FROM DISTRICT HEATING NETWORK
ELECTRICITY 35%
STEAM TO DISTRICT HEATING 45%
FUEL AND RADIATION LOSSES 12%
STACK LOSSES 8%

FIGURE 6-16
DIESEL ENGINE TOPPING CYCLE

As in the case of the gas turbine topping cycle, electricity can be produced by the diesel engine topping cycle at maximum capacity independently of the heating load, with the heat recovery equipment bypassed on the exhaust side of the engine.

Other advantages of the diesel cycle plant include capability of unmanned operation and moderate investment costs. The disadvantages are that only liquid and gaseous fuels can be used, though inferior grades of liquid fuels can be used, particular with slow speed engines.

The selection of heat recovery options for a diesel engine plant requires evaluation of capital and operating costs. A large number of sources of heat recovery are available (e.g. cylinder jacket cooling, lube oil cooling, charge air cooling, piston cooling, turbo charger cooling, and exhaust gases). Most of the above can make a significant contribution to a low grade heat requirement such as a hot water distribution system.

Figure 6-17 illustrates typical total unit capital costs ($/kW) for diesel topping cycles. The horizontal axis indicates the thermal outputs of the unit (MW). Typical electrical outputs at indicated thermal loads are also indicated. No attempt has been made to select a suitable thermal cycle. The relationship of thermal output to electrical output is therefore not optimized but represents merely a rule of thumb guide. The maximum heat to power ratio for recovery of only exhaust gases is 1:1. However, heat to power ratios of up to 5:1 are possible utilizing supplementary firing of the waste heat boiler and other engine sources of heat. A separate thermal output scale is shown for the medium speed and the slow speed diesels since generally higher exhaust gas temperatures are available with medium speed diesels. The costs are provided as an estimating guideline to provide the reader with approximate total cost of a diesel topping system. The estimated costs are for single units installed in

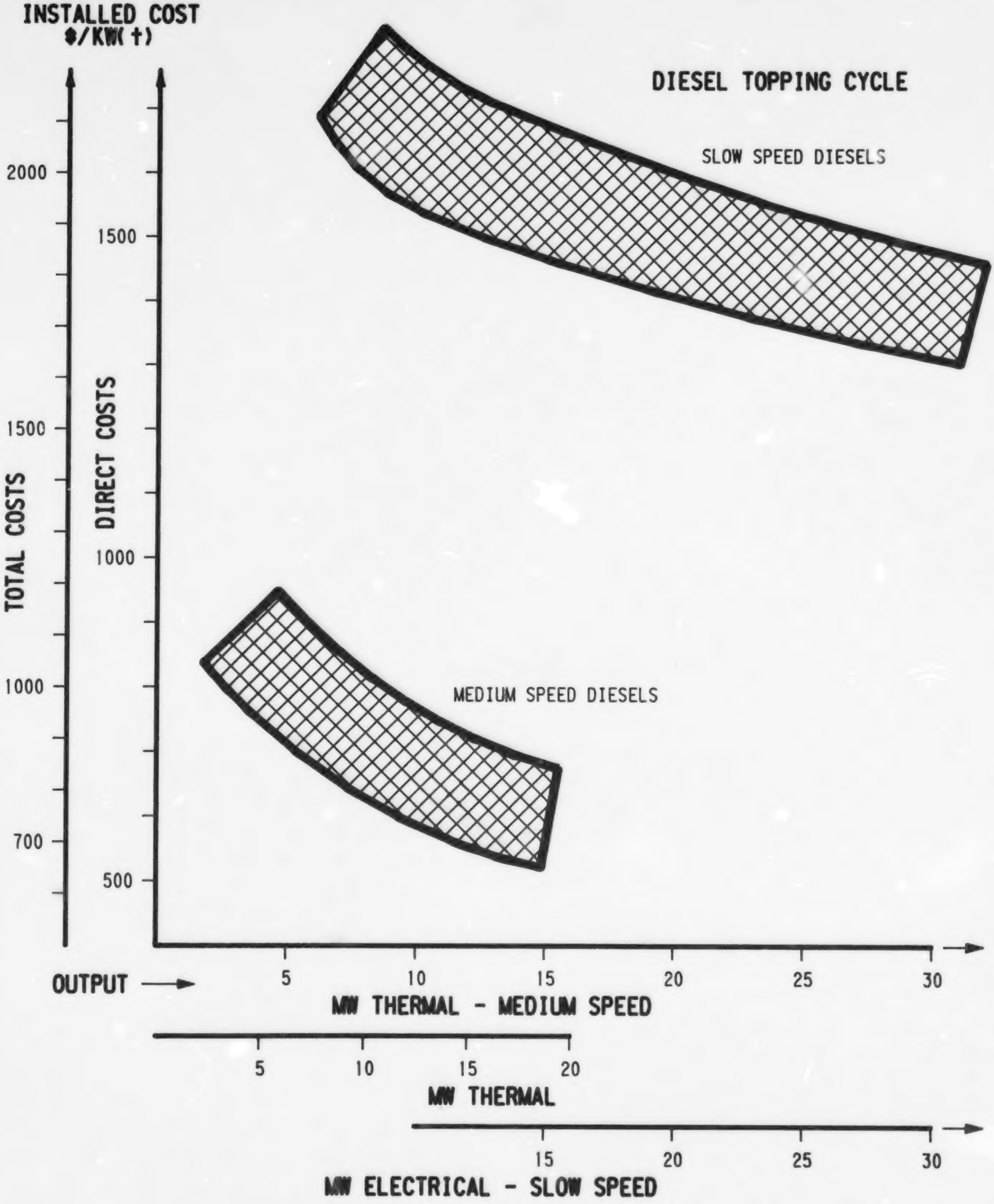


FIGURE 6-17
DIESEL TOPPING CYCLE
ESTIMATED TOTAL UNIT CAPITAL COST

a multi-unit station. The indirect costs were assumed to be typically thirt percent of direct costs.

Diesel electric plants are not common in urban Canada. Remote northern Canadian utilize diesel generators to provide electricity, and recovery of the waste heat is feasible alternative for providing community heating. The higher fuel costs in isolated communities make them good candidates for recovery of waste heat from diesel engines.

A study funded by Alaska Power Authority (Design Manual and Demonstration Results for Waste Heat Recovery in Rural Alaska by Raj Bhargava Associates, 1983) (201) evaluated the feasibility of waste heat/district heating installations in rural Alaskan communities.

The systems for three towns (Unalaska, Ouzinkie and Seven Mile) were monitored for a year. This demonstration project provided direct evidence of the economic feasibility and operability of waste heat recovery systems in rural Alaska. A summary of the results is as follows:

	Actual Payback Period at Current Operation	Theoretical Payback Period as Designed
Unalaska	5.8 yrs.	3.5 yrs.
Ouzinkie	12.5 yrs.	9.7 yrs.
Seven Mile Camp	5.4 yrs.	2.9 yrs.

This Alaskan study is very useful, in that, not only is the feasibility of demonstration projects proven, but a method of evaluation is provided to illustrate technical and economic criteria which must be considered.

.7 Bottoming Cycle

In the bottoming cycle, the fuel is burned in an industrial process and the heat from the exhaust gases is recovered. A typical schematic of a bottoming cycle is illustrated in Figure 6-18. The heat recovery boiler produces the steam which drives the backpressure steam turbine. The exhaust steam from the turbine is passed through the district heater.

The advantage of the bottoming cycle is that it reduces the amount of electrical power that an industry needs to buy in a relatively simple and straightforward manner. The cycle offers a means of producing electricity without increasing the air pollution at a particular site.

In order to utilize a bottoming cycle for district heating, the source of waste heat must be relatively close to the heat load.

For a futher discussion of the utilization of waste heat in DH systems, refer to Section 635 (Waste Heat Recovery Systems) of this report.

634 HEAT PUMP SYSTEM

In recent years, heat pumps have attained popularity in North America, especially for residential use. Heat pumps are also available for commercial and industrial applications, and have been utilized in Europe for district heating applications. The International Energy Agency (IEA) has investigated heat pumps and published "Heat Pump Systems - A Technology Review" (113). Much of the following information is excerpted from this publication.

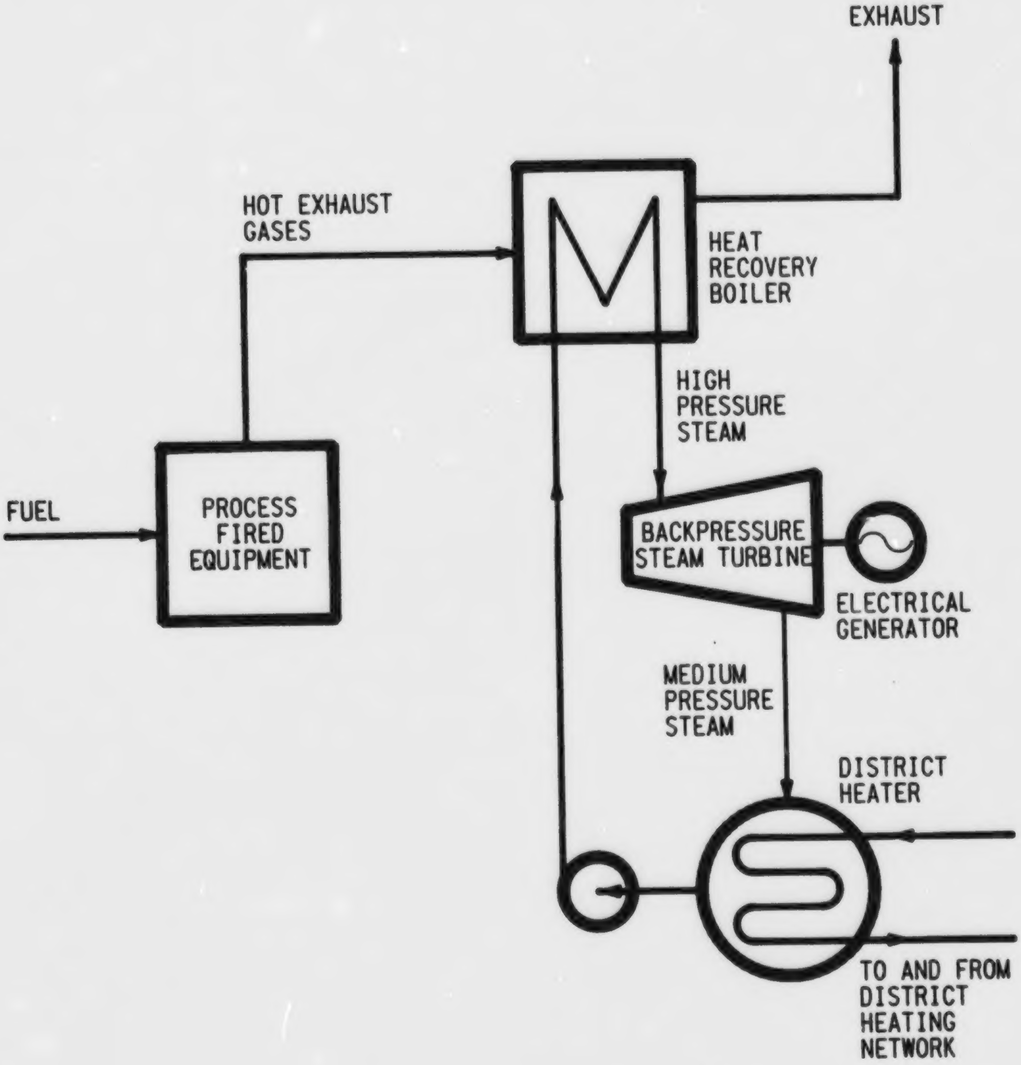

EXHAUST
HOT EXHAUST GASES
HEAT RECOVERY BOILER
HIGH PRESSURE STEAM
FUEL
PROCESS FIRED EQUIPMENT
BACKPRESSURE STEAM TURBINE
ELECTRICAL GENERATOR
MEDIUM PRESSURE STEAM
DISTRICT HEATER
TO AND FROM DISTRICT HEATING NETWORK

FIGURE 6-18
BOTTOMING CYCLE

A heat pump is a device which takes up heat at a certain temperature and releases this heat at a higher temperature. When operated to provide heat (e.g. for space heating or water heating), the heat pump is said to operate in the heating mode; when operated to remove heat (e.g. for air-conditioning), it is said to operate in the cooling mode. In both cases, additional energy has to be provided to drive the pump. Overall, this operation becomes attractive, in energy terms, if the total output is greater than the energy used to drive the heat pump, and economically attractive if the total life cycle cost (heat pump installation, maintenance and operating costs) is lower than that of a competing device.

The heat source for a heat pump is usually air, although water is also used. To date, soil has been used as a heat source in only a small number of cases. Where the heat pump provides both heating and cooling, air is the most common distribution medium. For heating only, air is also a common medium, except in those regions (e.g. Europe and parts of the United States) where many water distribution systems are installed in the residential sector. The energy needed to drive a heat pump is normally provided by electricity or fossil fuels, such as oil or gas.

Some of the low grade heat sources that are suitable for DH systems include:

- water deposits (rivers, lakes, sea water);
- geothermal energy;
- industrial/ municipal effluents and emissions;
- electric utility waste heat.

Most of these heat sources involve use of contaminated water and therefore corrosion and scaling of equipment must be carefully considered to avoid major problems.

The general characteristics of some typical commercially available heat pump systems are outlined in Table 6-25 for the residential, commercial and industrial sectors. For the commercial sector, all the basic characteristics are similar to those in the residential sector except for the fuel drive. In the former sector, a greater variety of fuels can be used because of the larger-scale operation which suits fossil engine systems. In industry, large-scale uses also result in greater fuel flexibility and the heat source is usually waste hot water, steam or humid air. The heat sink will depend on the particular industrial process.

TABLE 6-25

Typical Heat Pump Characteristics

	Residential[1]	Commercial[2]	Industry
Fuel	Electricity	Electricity	Electricity, gas or oil
Heat Source	Air, soil or water	Air, soil or water	Warm water, air or steam
Heat Sink	Air or water	Air or water	Process
Market Segment	New, retrofit	New, retrofit	Process
Use	Heating and/or cooling	Heating and/or cooling	Heating
Machine Costs '82 (US$ per kW of output)			
Group I[3]	Less than 400	Less than 300	Process Specific
Group II[4]	400-1200	300-600	Process Specific

---

[1] 1-2 family houses.

[2] Includes multi-family houses and industrial space heating as well as the commercial sector.

[3] Group I includes the United States, Japan and, in some cases, Germany.

[4] Group II includes all other countries, as well as those cases for Germany not included in Group I.

The most common type of heat pump is the electric heat pump. The basic component of the electric heat pump is an electrically-driven reverse Rankine cycle compressor using a fluorocarbon refrigerant as working fluid. This heat pump, with minor modifications, has been commercially available from several manufacturers for a number of decades. High-efficiency heat pumps, representing improvements of the standard systems have become available only within the last few years. For low external temperature operation during cold periods, the heat pump output may be supplemented by electric resistance heating often (apart from Europe) incorporated in the heat pump unit.

The heat pump runs on an evaporation-condensation cycle, just like traditional air-conditioners and refrigerators. A typical vapour-compression electric heat pump (Figure 6-19) has several vital components: a working fluid called a refrigerant that circulates continuously in a closed cycle, a motor driven compressor, a pair of heat exchangers which can alternate in the roles of condenser and evaporator, and some form of expansion valve that can be used to control the pressure drop and hence the temperature change of the working fluid. A reversing valve is also needed if the heat pump is to be used in the dual mode for both heating and cooling.

The working fluid will generally be one of the freon fluids suitably selected to meet temperature rise and compressor characteristics of the system.

A typical schematic of a district heating network supplied by a heat pump is shown on Figure 6-20.

The operation of the heat pump is measured by its co-efficient of performance (COP) which is defined as the ratio of useful heat energy output to the drive energy. COP depends on a number of factors, among them the temperature rise between the input source and the output. European district heating installations have

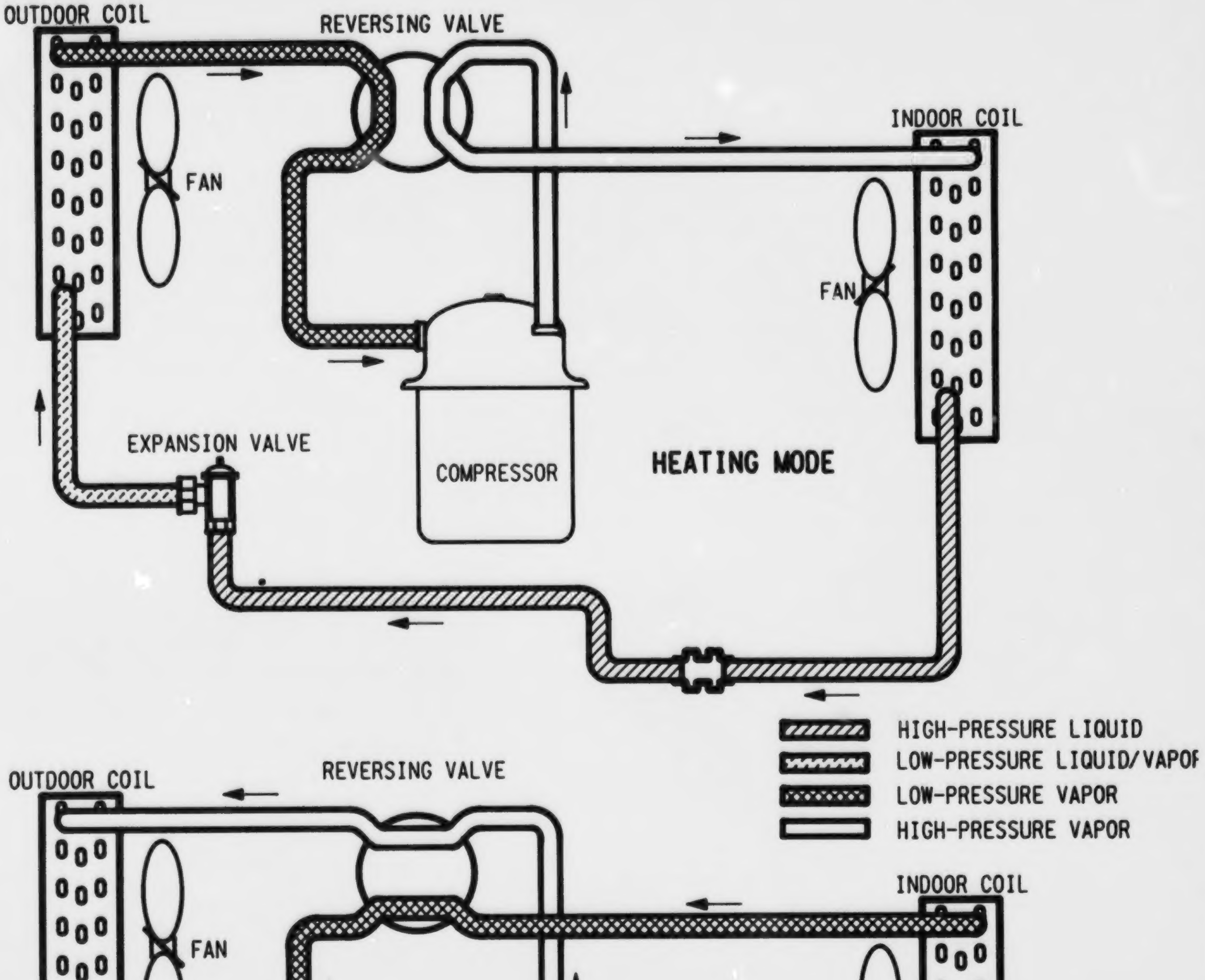

OUTDOOR COIL
REVERSING VALVE
FAN
INDOOR COIL
FAN
EXPANSION VALVE
COMPRESSOR
HEATING MODE
▨ HIGH-PRESSURE LIQUID
▨ LOW-PRESSURE LIQUID/VAPOR
▨ LOW-PRESSURE VAPOR
☐ HIGH-PRESSURE VAPOR
OUTDOOR COIL
REVERSING VALVE
FAN
INDOOR COIL
FAN
COOLING MODE
COMPRESSOR
EXPANSION VALVE

FIGURE 6-19
HEAT PUMP OPERATION

SOURCE: EPRI JOURNAL MAY 1981

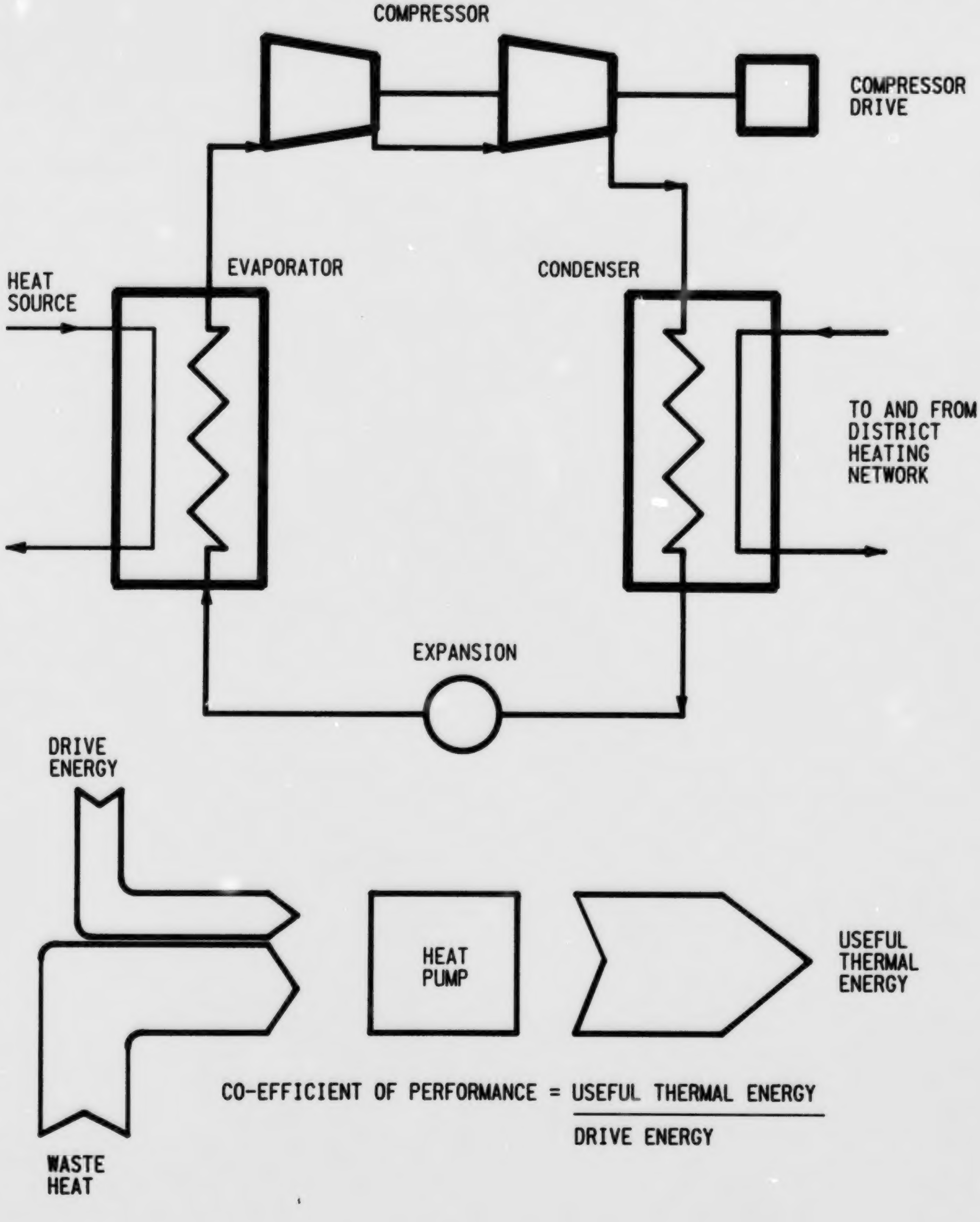

COMPRESSOR
COMPRESSOR DRIVE
EVAPORATOR
CONDENSER
HEAT SOURCE
TO AND FROM DISTRICT HEATING NETWORK
EXPANSION
DRIVE ENERGY
HEAT PUMP
USEFUL THERMAL ENERGY
WASTE HEAT
CO-EFFICIENT OF PERFORMANCE = USEFUL THERMAL ENERGY / DRIVE ENERGY

FIGURE 6-20
HEAT PUMP STATION SCHEMATIC

average COP's in the range of 2.8 to 3.6, with heat source temperatures as low as 2°C and outputs of 60-80°C. Heat pump units are available in sizes up to between 10 and 20 MW thermal output.

Types of compressors include centrifugal, reciprocating and screw type. Due to a low COP and limited capacity, reciprocating compressors are not generally suitable. Screw and centrifugal type compressors are suitable for heat pumps, and will have similar performance characteristics. The centrifugal type is well-proven in air-conditioning installations. The screw compressor is not commercially available in larger sizes, although possible advantages include capability to operate at higher temperatures and pressure differentials.

Common compressor drives include electric motor, diesel engine, gas turbine and steam turbine.

In addition to Rankine type heat pumps, absorption cycle heat pumps may also be applied to district heating.

In many respects, an analogy may be said to exist between an absorption refrigeration cycle and a vapour compression or Rankine cycle. In the latter case, a compressor is used to increase the pressure of the refrigerant vapour prior to its condensation; in the former case, the physical affinity between a refrigerant vapour and an absorbent solution is used and a solution pump produces a similar effect. Absorption air-conditioning machines are commercially available today in the United States and Japan in large sizes. Some smaller unitary residential and commercial absorption cycle air-conditioners are being produced by one manufacturer, but to a steadily shrinking share of the total market.

Absorption cycle heat pumps, depending somewhat on the cycle and the particular design configuration employed, have the following major advantages:

- Inherently simple and potentially highly reliable equipment, in that the solution pump, air-moving fans (or water pumps for water-cooled systems) and purge pumps (where required) are the only moving parts (no compressor is needed).

- High efficiencies in the heating mode due to the possibility of heat transfer from on-site combustion into the absorption cycle.

- Refrigerant-absorbent fluids can be used which are chemically non-reactive with atmospheric ozone, although some of the promising working pairs include chloro-fluorocarbons.

- Cycle reversal or hot refrigerant by-pass are practicable for evaporator defrost.

The cost-effectiveness of an absoprtion heat pump is very much a function of the fluids used. The gas-fired absorption heat pump benefits from having the fuel combustion take place on-site just as a thermal engine heat pump does, but the former is much simpler insofar as lack of reciprocating or rotating machinery is concerned. The on-site waste heat is available as supplementary heat and, for evaporator defrost, this aspect is important not only from the standpoint of efficiency and reliability but also because refrigerant flow reversal is not as easily handled as with Rankine cycle machines.

Absorption cycle heat pumps also have a number of disadvantages:

- Comparatively large heat-exchanger areas (at attendant high first-cost) required for realization of acceptable performance (expensive rectifiers may also be needed).

- Usually lower cooling-mode performance than obtainable with Rankine refrigeration machinery (including electric heat pumps).

- Toxicity of ammonia, where used, requires that direct refrigerant/conditioned air contact in water/ammonia systems must be avoided (necessitating the use of either a water loop or other intermediate means of heat transfer).

- Corrosiveness of water-ammonia systems requires the use of steel rather than aluminum or copper in the manufacture of the heat pump (the organic absorption system uses aluminum).

- Diameter limitation of the absorber requires the use of a tall unit with attendant bulkiness of equipment.

- Unfamiliarity of technical experts with the plumbing of absorption machines.

- Poor operating performance compared with engine-driven systems.

- Dependence on the availability of scarce fossil fuels (e.g. natural gas).

- Weight of the units.

- Reduced performance due to losses resulting from use of on/off control systems.

Another problem is that initial experience with water/ammonia absorption-cycle gas air-conditioners has not been good, and their market share has decreased steadily. This is attributed to high cost and equipment reliability problems. In addition, while new installations will use primary energy more efficiently, they are also liable to increase consumption of and dependence on fuels such as natural gas, etc.

Basically, two types of heat pump have been described in this section, however, heat pump technology is undergoing significant technical development. Table 6-26 illustrates the status of heat pump technologies in the mechanical (compression/expansion), chemical (absoprtion), electrical and magnetic types for heating and cooling.

As previously noted, heat pumps are gaining popularity in Canada for single dwelling applications, but have not yet been seriously considered for district heating systems. However, many such systems have been recently installed in Europe, as listed in Table 6-20.

Heat pump installations may also be applied as heat cascading devices in district heating systems. For example, if a fossil-fired cogeneration plant supplies a district heating system with hot water, heat pumps may be utilized to upgrade and reuse the return water to the heating plant. The return water would then be at a lower temperature which would increase the amount of fuel burnt to obtain constant heating plant output conditions. This may require an increase in plant capacity. Depending on the cost of electricity to drive the heat pumps, the use of heat pumps in a cascading system may be an economically feasible alternative. This technology may best be utilized in district heating retrofit situations.

Based on European experience in heat pump installations the Stal Refrigeration Group conclude that:

- Heat pump plants are reliable if properly designed.

- Maintenance costs will normally not exceed the cost of an oil-fired boiler installation of equal capacity.

TABLE 6-26

Status of Heat Pump Technologies[a]

Type	Cooling[b]	Heating[c]
Mechanical (compression/expansion)		
Rankine cycle		
Electric motor driven	Available	Available[d]
Steam turbine driven	Available	Not used
Combustion engine driven		
Diesel	Available	Available
Otto	Available	Available
Brayton	Development	Development
Stirling	Development	Development
Solar driven (organic Rankine)	Prototype	Prototype
High temperature (industrial)		
Rankine	NA	Prototype
Brayton	NA	Development
Brayton cycle		
Closed	Development	Development
Open air-cycle	Prototype	Development
Stirling cycle	Prototype	Prototype
Chemical (absorption)		
Lithium bromide/water		
Steam and hot water (from boilers)	Available	Not used
Direct fired (gas or oil)	Available	Prototype
Solar and recovered heat	Prototype	Development
Ammonia/water	Available	Development
Ammoniated salts	Development	Development
Hydrated salts	Development	Development
Metal hydrides	Development	Development
Methanol-based	Development	Development
Sulphuric acid/water	Development	Development
Zeolites	Development	Development
Electrical (Peltier effect)	Development	Development
Magnetic	Development	Development

[a] Status is characterized as follows:

Development:	in initial research, undergoing conceptual analysis and/or laboratory testing.
Prototype:	undergoing field testing.
Available:	commercially marketed with one or more successful applications.
Not used:	a proven concept that is not currently being developed, tested, or applied for economic reasons.

[b] For space, water, or process cooling, or for refrigeration.

[c] For space, water, or process heating.

[d] Most heat pumps in current use are of this type. Residential units usually employ R22 as the refrigerant; commercial and industrial units usually use R22, other chlorofluorocarbons, other organic fluids, or ammonia as refrigerants.

NA = Not Applicable.

Source: Argonne National Laboratories ANL/CNSV-18, 1981. (37)

- The heat pump system can be cost-effective when properly designed.

- Higher energy prices will increase profitability.

- Heat pumps are already available in the required capacity range and adapted to the various heat sources available.

- Know-how is already available for comprehensive plant analysis and design.

The use of heat pumps for district heating could be viable in certain densely populated regions of Canada. The best system varies from region to region and depends on climate and relative fuel prices. As in the case of district heating generally, the major obstacles are economic and institutional rather than technical in nature. However, as discussed in Part 662.10, there is limited experience in the commercial operation of large heat pumps in district heating service.

635 WASTE HEAT RECOVERY SYSTEMS (ENERGY CASCADING)

.1 Industrial Waste Heat

Industrial waste energy is one of the possible local sources of energy which can be utilized for district heating. Energy cascading in the industrial sector can be defined as the organization of the flow of energy through the various thermal systems, production processes and equipment in an industrial plant operation, to achieve the maximum efficiency of energy use. Typical industries from which energy may be recovered include oil refineries, chemical plants and steel mills. The main intent of energy cascading is to use the heat output of one process as the input to another process. After the heat has been reduced to such a low quality that it is no longer useful for industrial purposes, it may be utilized outside the plant boundaries for such uses as district heating.

Equipment required for energy cascading includes heat recovery boilers, heat exchangers and heat pumps, which are readily available from various manufacturers. Details of typical systems for various industries are very site specific and beyond the scope of this report. However, the following two diagrams illustrate how waste heat from energy may be beneficially utilized.

Figure 6-21 shows how, in an endothermic process, it is possible to minimize the discharges and hence the level of thermal pollution by re-using available heat to produce hot water at a temperature equal to or greater than 90°C.

Figure 6-22 shows an example of an ideal energy cascading system.

The Commission of the European Communities in Luxembourg conducted a study entitled "Waste Heat from Industry for District Heating" (54) which concluded that incorporating recoverable industrial waste heat with (all the) other local energy sources available gives rise to a flexible energy supply system better able to cope with cyclical variations in cost. The following two sub-sections are excerpts of this study and discuss sources and methods of assessing the potential waste heat from industry usable for district heating.

.2 Sources of Waste Heat from Industry Usable for Domestic Heating

In general terms, usable waste industrial heat is generated by processes involving high temperatures (250°C), whether during exothermic or chemical reactions or in reactions involving a change of state (fusion, vaporization, etc.).

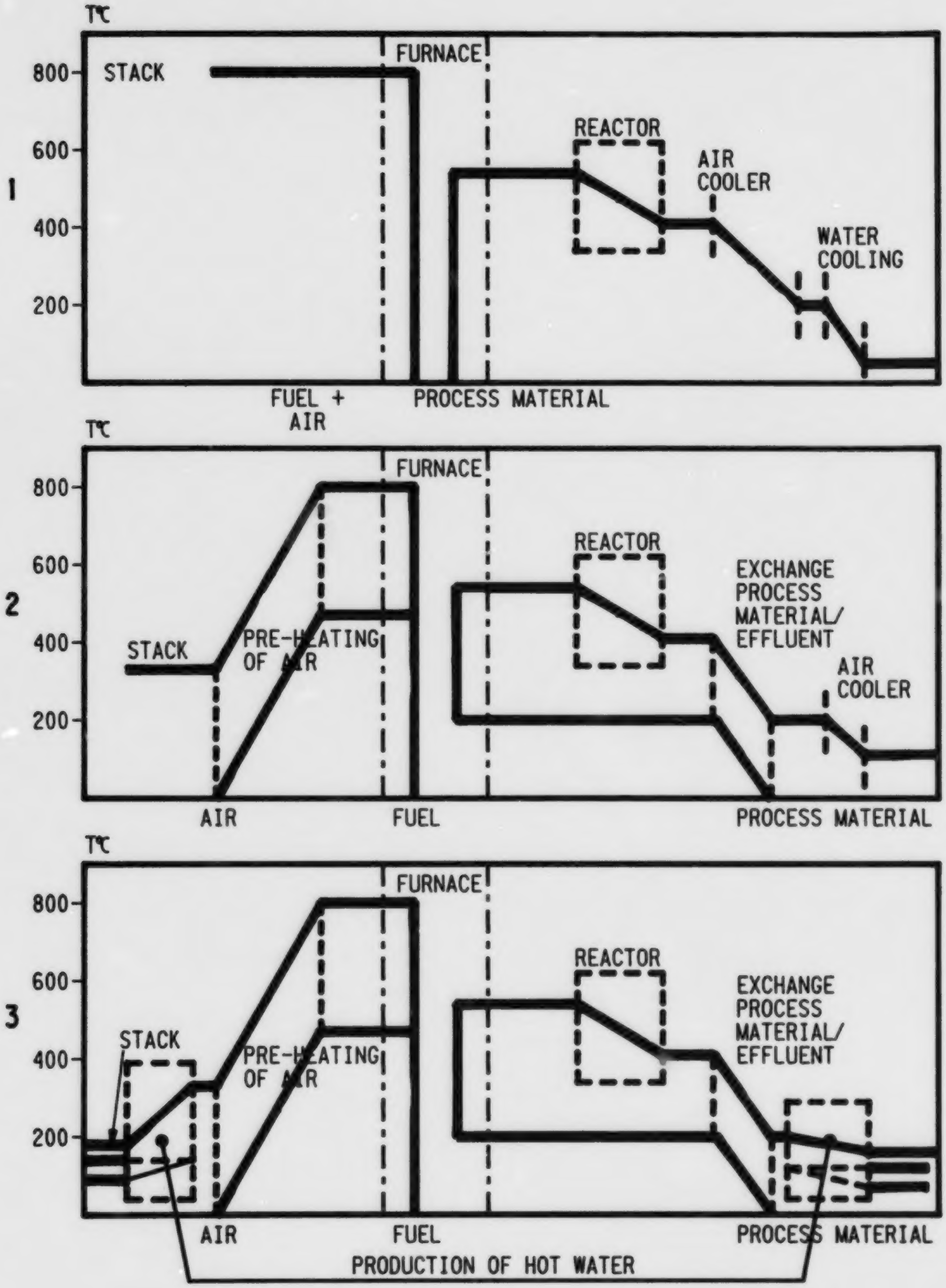
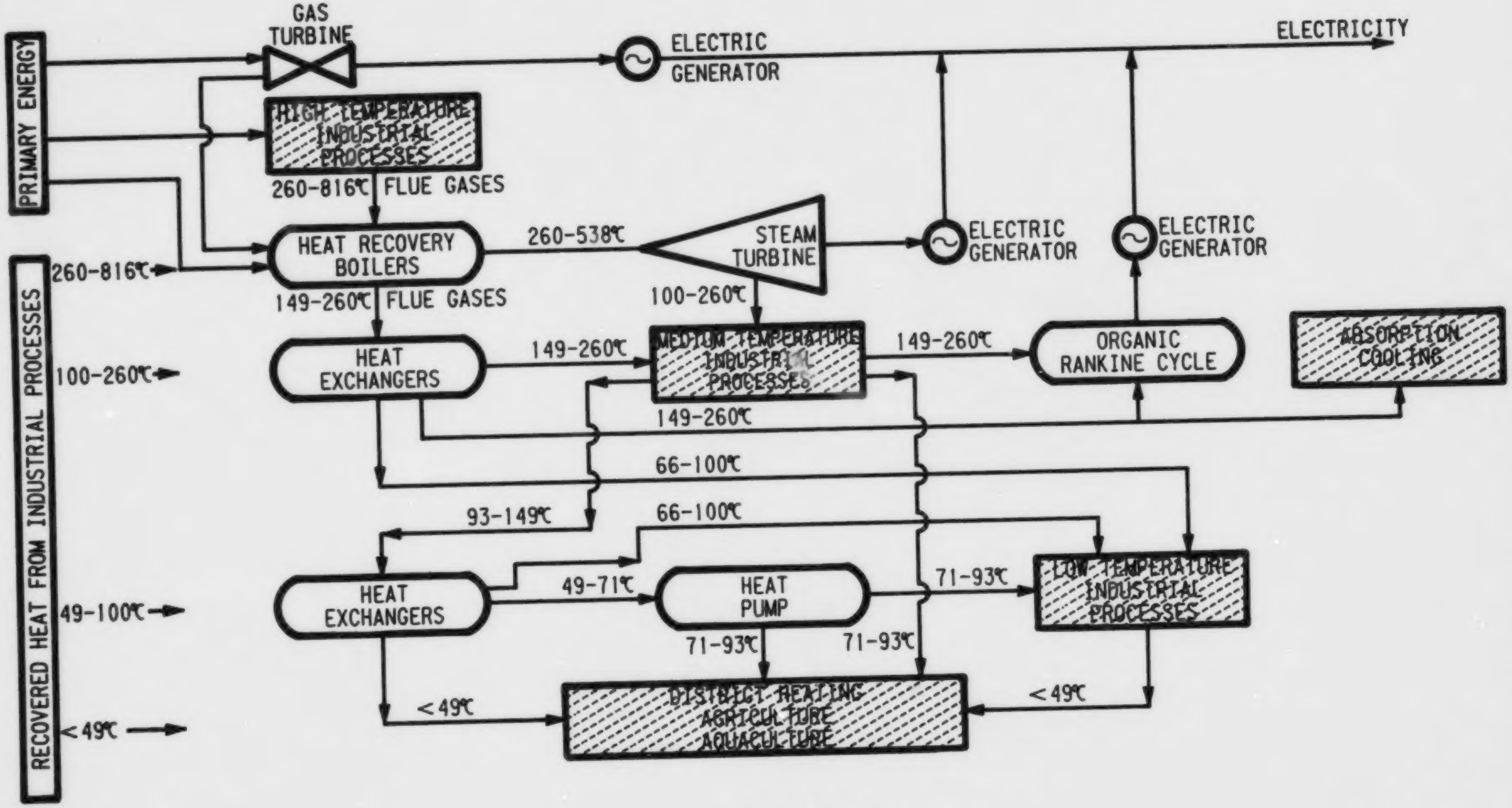

T°C
800
600
400
200
1
STACK
FURNACE
REACTOR
AIR COOLER
WATER COOLING
FUEL + AIR
PROCESS MATERIAL
T°C
2
STACK
PRE-HEATING OF AIR
FURNACE
REACTOR
EXCHANGE PROCESS MATERIAL/ EFFLUENT
AIR COOLER
AIR
FUEL
PROCESS MATERIAL
T°C
3
STACK
PRE-HEATING OF AIR
FURNACE
REACTOR
EXCHANGE PROCESS MATERIAL/ EFFLUENT
AIR
FUEL
PROCESS MATERIAL
PRODUCTION OF HOT WATER

FIGURE 6-21
1) INITIAL SITUATION (POLLUTION + HEAT DISCHARGES)
2) OPTIMIZATION WITHIN THE UNIT (TOTAL ENERGY SYSTEM)
3) USE OF INDUSTRIAL WASTE HEAT TO PRODUCE HOT WATER

SOURCE: WASTE HEAT FROM INDUSTRY FOR DISTRICT HEATING
COMMISSION OF THE EUROPEAN COMMUNITY, LUXEMBURG


PRIMARY ENERGY
RECOVERED HEAT FROM INDUSTRIAL PROCESSES
260-816℃
100-260℃
49-100℃
<49℃
GAS TURBINE
ELECTRIC GENERATOR
ELECTRICITY
HIGH TEMPERATURE INDUSTRIAL PROCESSES
260-816℃ FLUE GASES
HEAT RECOVERY BOILERS
260-538℃
STEAM TURBINE
ELECTRIC GENERATOR
ELECTRIC GENERATOR
149-260℃ FLUE GASES
100-260℃
HEAT EXCHANGERS
149-260℃
MEDIUM TEMPERATURE INDUSTRIAL PROCESSES
149-260℃
ORGANIC RANKINE CYCLE
ABSORPTION COOLING
149-260℃
66-100℃
93-149℃
66-100℃
HEAT EXCHANGERS
49-71℃
HEAT PUMP
71-93℃
LOW TEMPERATURE INDUSTRIAL PROCESSES
71-93℃
71-93℃
<49℃
<49℃
DISTRICT HEATING AGRICULTURE AQUACULTURE

SOURCE:
ENERGY CASCADING POTENTIAL IN CANADIAN INDUSTRY ENERGY,
MINES AND RESOURCES CANADA INDUSTRY SERIES, PUBLICATION #3a, 1981

FIGURE 6-22
EXAMPLE OF AN IDEAL
ENERGY CASCADING SYSTEM

In oxidation or combustion reactions, initial heat recovery generally takes place in the unit, either in a waste-heat boiler for steam-raising or during the preheating of the combustion air or the process material. The gases, fumes or vapours are thus brought up to a temperature of between 200 and 300°C. It is then possible to produce hot water by bringing the temperature close to dew-point, if the environment is corrosive, or to a lower temperature in other cases.

In endothermic processes, the reagents or the process materials have to be introduced at a high temperature (e.g. 500°C for naphtha reforming, 350°C for distillation of crude); this generally takes place in furnaces. Energy can therefore be recovered from the furnace waste gases.

The products must then be cooled (condenser at the top of the distillation column or process material/effluent exchangers) which allows secondary heat recovery to take place (See Figure 6-21).

More generally, wherever a plant incorporates an air cooler or a heat exchanger in the cooling water circuit, the possibility exists for simultaneous hot water production.

.3 Method of Assessing the Potential Waste Heat from Industry Usable for District Heating

A global approach has been adopted, in view of the large number of industrial complexes to be investigated in the European Community.

The potential supply of waste heat from industry has been assessed in one of two ways, i.e.:

Either:

1. Directly, using ratios based on output capacity.

The processes used in the manufacture of basic and intermediate products are well known. It has thus been possible to estimate the amount of energy to produce hot water (T 90°C) available per tonne produced or treated.

Or:

2. Indirectly, by evaluating the total industrial heat potential of a plant and by applying a weighting factor to determine the proportion that may be recovered in hot water.

On the other hand, where plants operate a total energy system and manufacture a wide range of finished products (e.g. basic chemicals and synthetic textiles), the amount of recoverable heat has been estimated as a proportion of the total energy consumption and, where necessary, these figures have been discussed with the industries concerned.

In certain cases, the estimated potential has been weighted by an "availability factor" which takes account of the following specific criteria:

1. The technology used in the recovery equipment and the effluent characteristics (corrosion, etc.).

2. The age of the plants and the degree of energy integration which they have achieved.

3. A reasonable level of investment in recovery equipment.

4. The attitude, for or against, of industrialists to such energy recovery operations.

A detailed discussion of the industrial processes is beyond the scope of this report, however, Table 6-27 indicates the estimated quantities of recoverable heat from the studied industries.

636 RETROFIT OF EXISTING POWER PLANTS

Thermal electricity generating stations that are relatively close to load centres can be modified to serve as the heat source for district heating systems. Techniques for retrofitting existing power plants include:

- Modifications to existing turbines.
- Installation of new specially manufactured extraction turbines.
- Conversion of existing steam boilers or installation of new hot water boilers.
- Installation of waste heat boilers on existing gas turbines.
- Installation of waste heat boilers and recovery of jacket cooling heat from diesel generator installations.

A short description of each of these retrofits is provided in the following sub-sections.

TABLE 6-27

Estimated Quantities of Recoverable Heat

INDUSTRY	PROCESS	RECOVERABLE HEAT PER TONNE OF PROCESS PRODUCT (MJ/t)	REMARKS
OIL REFINING		23.88	
CHEMICAL PLANTS	Petrochemicals		
	a) Steam Cracking Plant		Details of the heat recovery potential are given. The overall waste heat potential in this type of complex (based on the ethylene output capacity) is 191 MJ/t.
	- Ethylene	107.5	
	- Hydrocracking of gasoline-type oils	10.75	
	- Butadiene	28.66	
	- Aromatics	28.66	
	- Styrene	95.52	
	- Ethylene Oxide	238.8	
	Feedstock Products for the Inorganic Chemical Industry		
	a) Chemistry of Nitrogen		
	- Ammonia	171.94	
	- Nitric Acid	95.52	
	- Ammonium Nitrates	65.5	
	- Urea	4.78	
	b) Sulphuric Acid	95.52	
	Methanol	167.16	
	Industrial Gas (i.e. Oxygen)	5.73	
STEEL	Coking Plants	2.87 - 3.58	
	Sintering of Ore	4.78	
	Blast Furnaces	4.78	
	Steelworks		
	- Steelworks	23.88	In small scale plants, where there is total combustion of the gas.
		7.16	When the combustion is incomplete
	- Electric Steel Plants	5.97-7.16	
	Rolling Mills		
	- Ingot Casting	10.75 - 13.13	
	- Continuous Casting	7.16 - 8.36	

.1 Modifications to Existing Turbines

Depending on the original design of the steam turbine, many types of modifications can be considered.

One type of modification which does not require changes to the turbine involves passing the DH water through the condenser. To maximize heat pick-up, the backpressure of the condenser is increased to the maximum value allowed by the manufacturer. The DH water is then further heated in a district heater which is fed with steam from existing extraction points (for single casing turbines) or from the IP/LP crossover (for multi-casing turbines).

The reduction in electricity varies by the amount of steam extracted. Typically for an IP/LP crossover extraction conversion, for a 6% maximum steam extraction the electricity loss is 10.2%, and for a 12% maximum steam extraction the electricity loss is 13.7%. The ratio of electricity lost to the extracted heat is 0.083 and 0.11 MW(e)/MW(t), respectively.

Another method of turbine modifications which is suitable for multi-casing machines is a condensing tail conversion which involves replacement of the low pressure section with a new section designed for increased steam extraction. Typically, two large extraction points could be provided in the new low pressure section to supply steam to two district heaters arranged in series. If required, prior to passing the DH water through the district heaters, preheating may be attained by passing the water through the first low pressure heater.

A final method of modifying existing turbines involves conversion of the turbine to a straight backpressure unit. The condenser is replaced with a district water heater and the turbine's exhaust pressure is raised by removing the low pressure stages. If heat loads and electric loads can be balanced, this system provides the highest overall operating efficiency.

As can be seen from the descriptions of feasible modifications, retrofitting of existing power plants to heat district heating water is dependent on original power plant design (i.e. very site specific). Not only must the heat load curve and effect of lost electricity be evaluated, but the physical layout of the power plant must be carefully examined to ensure considered retrofits are possible within the available space. Some of the modifications discussed above entail installation of district heat exchangers, and routing of large extraction steam lines may prove a problem.

A study in the U.S. by the Oak Ridge National Laboratory (ORNL/TM-6830/P9) (79) summarizes the advantages and disadvantages of the backpressure turbine conversion and condensing tail turbine conversion as follows.

A backpressure turbine conversion has three main advantages:

1. Overall efficiency is high because all the energy contained in the exhaust steam is either used in the DH (district heating) system or returned to the cycle in the condensate. This is independent of the thermal efficiency of the turbine and the parameters of the main steam flow.

2. The capital cost of the conversion is usually less than for conversion to a condensing-tail turbine.

3. In its basic form, a backpressure conversion requires a comparatively simple control system.

The backpressure conversion also has some significant disadvantages:

1. The maximum achievable temperature of the DH water is limited to a few degrees below the saturation temperature of the turbine exhaust steam. To avoid excessive sacrifice of electrical capability, the exhaust pressure (and therefore the water temperature) should be kept as low as possible. Usually the maximum potential exhaust pressure is about 137.9 kPa (20 psia), with a corresponding DH water temperature of 104-107°C (220-225°F).

2. In the basic backpressure scheme, electrical production is strictly proportional to the heat load. This establishes the amount of steam which can be condensed and, therefore, the amount which can pass through the turbine. For any turbine-generator of significant size, this is an undesirable situation, since electrical demand does not normally exhibit the magnitude of seasonal variation of space heating loads. When thermal load is low, electrical production can be increased by several methods. Excess steam can be exhausted to an auxiliary condenser, or the heat load can also be increased by cooling the incoming DH water in an auxiliary heat exchanger. Each of these modifications is undesirable because of the added complication and cost of the conversion. Electricity produced by either of these methods will also be more expensive than that produced with a standard condensing turbine.

3. Because some turbine stages have been removed and the turbine must always operate at an elevated back pressure, there is a permanent loss of electrical capacity.

The condensing-tail (extraction) turbine conversion offers several significant advantages:

1. No electrical capability is permanently lost. Any time the turbine is not required to satisfy a heat demand, it can be operated in the electric-only mode as if it had not been altered.

2. Because the steam is extracted from the intermediate- pressure-to-low-pressure crossover, no unbalanced thrust loads are introduced to the turbine bearings (assuming a two-flow low-pressure turbine. Mechanical modifications of the turbine are minimized.

3. Higher water temperatures are more feasible than with back-pressure turbines, because of the higher temperature and pressure of the crossover steam.

4. Electricity and heat are not produced in a fixed ratio but can be varied over a range. This variation provides more operational flexibility to accommodate system load requirements.

There are also certain disadvantages:

1. Major control modifications are required, and the new system is complex.

2. Because most of the energy contained in any steam exhausted to the condenser (a minimum flow for cooling the low-pressure turbine is always required) is discarded, this system is less efficient than a back-pressure conversion. However, the overall efficiency will never be less than the all-electric mode for which it was originally designed.

3. The cost of this conversion is usually considerably more than for a back-pressure conversion, due to the complex control system required.

Selection of the recommended conversion requires evaluation of each alternative with respect to a number of criteria. These include lowest cost, reliability, operating flexibility, burning coal in preference to gas or oil, constraints on converting existing units (mechanical and thermodynamic), available space, condition of equipment and equipment layout.

Studies have been conducted in Canada to determine the feasibility of converting existing power plants to supply heat for district heating systems. A typical study by Shawinigan Engineering Maritimes Ltd. (1977) (222) looked at utilizing the 20 MW turbine at Nova Scotia Power's Water Street G.S.

The study examined two alternatives:

- A low temperature steam system with a new turbine-generator set suitable for operating with variable backpressure to 345 kPa.

- A low temperature water system (115°C) with the existing 20 MW turbine-generator condensing unit converted to a pure back-pressure unit. The present turbine consists of a high pressure section connected to a low pressure section by crossover piping. The conversion to a pure backpressure mode of operation would require modifications to the HP and LP sections of the turbine. The total HP turbine steam exhaust would be diverted to new district heating condensers operating at a maximum of 172 kPa turbine backpressure. The electrical output of the unit would be 12.7 MW(e) after conversion.

The study concluded that both the district heating scheme alternatives were technically acceptable and economically viable.

.2 Installation of New Turbines

In the event that an existing turbine retrofit is not feasible, due to such constraints as listed in the previous paragraphs, installation of a new turbine may be feasible. Although the capital cost would be high, the turbine would be specifically designed to meet system electrical and heat demand requirements, thereby maximizing operating efficiency.

.3 Conversion of Existing Steam Boilers

In the event that steam generating facilities are no longer required for power generation, the boiler may be converted to a hot water boiler. Depending on the original design of the boiler and economics, the retrofit may also allow changing the fuel. Not including a fuel switch, a report by Argonne National Laboratory (ANL/CNSV-TM-11) (214) indicates that a boiler conversion from steam to hot water would cost approximately 15% of the original cost of the boiler.

If a boiler retrofit cannot meet the system demand, additional hot water bolers can also be installed to provide the extra capacity requirement.

.4 Installation of Waste Heat Boilers on Gas Turbines

Gas turbine exhaust gas in the range of 260-650°C (500-1200°F) may be utilized in a DH system by installation of a waste heat boiler. By reducing the exhaust gas temperature to about 160°C (320°F), the waste heat boiler could produce heat power double that of the initial electrical power produced by the gas turbine.

Figure 6-23 illustrates the exhaust gas temperature and exhaust heat recoverable for a typical 10 MW gas turbine for the complete load range. Refer to Section 633 for a description of the gas turbine topping cycle.

.5 Retrofit of Diesel Generator Installations

As with the gas turbine, diesel generators discharge large amounts of waste heat in exhaust gas. This heat can be utilized in a waste heat boiler for district heating. In addition, cooling jacket heat can also be recovered.

Refer to Section 633 for a description of the diesel engine topping cycle.

637 THERMAL STORAGE

The ability to store heating mediums, which can then be circulated in a DH network when required, allows utilization of heat sources which do not have the same availability pattern as the original heat source. Typical heat sources which require thermal storage include:

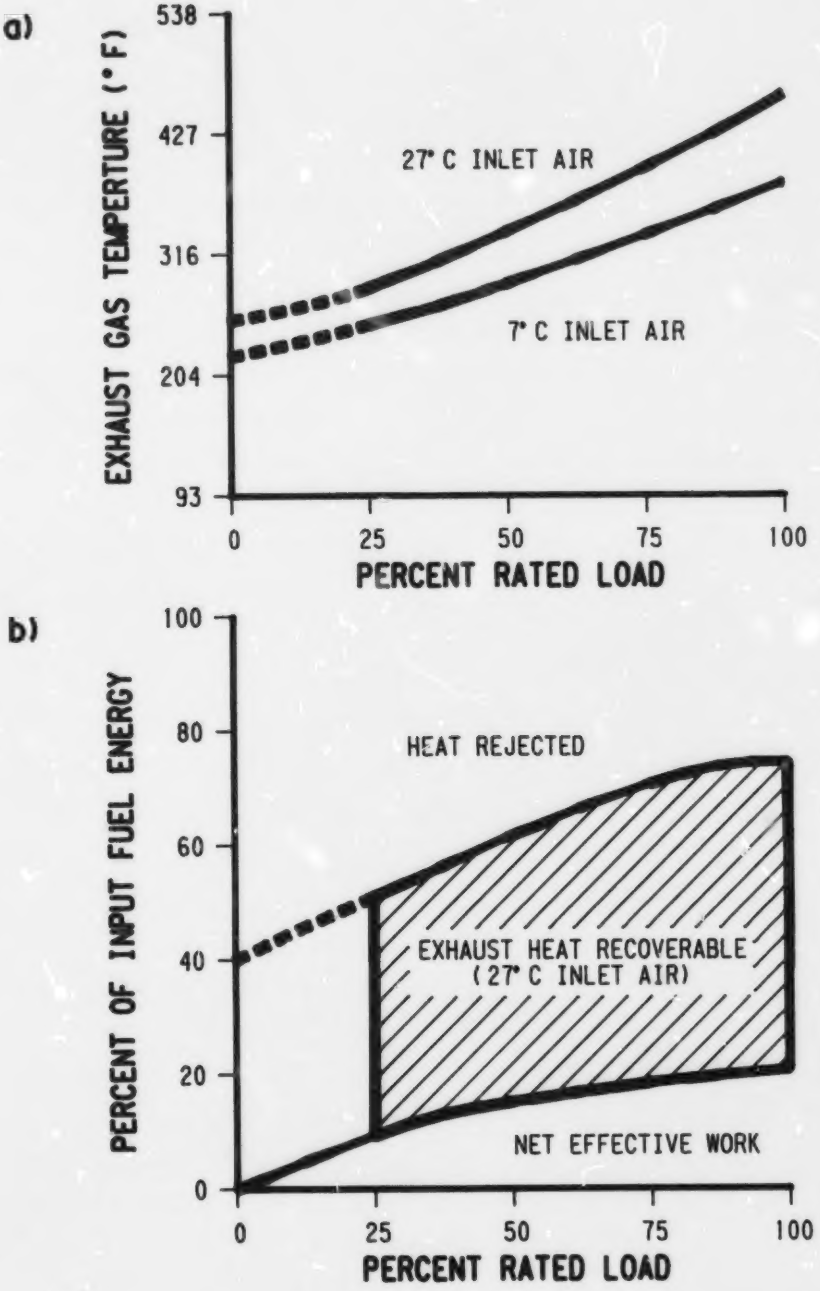


FIGURE 6-23
WASTE HEAT BOILER RETROFIT DATA
a) TEMPERATURE
b) HEAT

SOURCE: ARGONNE NATIONAL LABORATORY
(ANL/CNSV-TM-11)

[100,77]DSS623 .DGN

- Base-load fossil fuel and nuclear generating plants. Heat could be extracted from the power plant during off-peak hours, stored and utilized as required.

- Large heat pump systems which rely on municipal and industrial wastewater as a heat source. Wastewater flow is generally reduced during the night and thermal storage is required to maintain the DH load.

- Solar energy source systems.

Design of heat storage systems is very site specific, and the major points that should be evaluated are the thermal energy storage method, storage temperature, storage time, the type and construction of the storage facility and the location relative to the heat source and sink.

The three common methods of thermal energy storage include:

- Phase change energy storage - a phase change is accompanied by a substantial change in the internal energy of the material. The energy is stored in the form of latent heat. A high volumetric energy density is essential and hence systems involving solid-liquid phase transition are considered to be practical.

- Reversible thermochemical energy storage - the energy is stored as the bond energy of a chemical compound and it can be repeatedly stored and released in the same materals by reversible chemical reactions.

- Sensible heat thermal energy storage - thermal energy is stored in a solid or in a liquid in the form of sensible heat by increasing the temperature of the storage medium. This method is relatively cost effective for moderate storage times and a wide range of suitable storage mediums include hot water, organic fluids such as oil or Dowtherm, and steam (utilizing an accumulator system).

Of the three storage methods described, only the sensible heat storage systems have clearly reached commercial acceptance and usage on a large scale. Both latent heat and thermochemical methods are at early stages of development and are not yet considered practical for large scale installation.

As reported by U.S. Department of Energy (DOE/EA-0131) (254), the types of heat storage facilties include:

- Aquifer thermal energy storage - this system consists of a system of water supply wells drilled into an aquifer. During operation, the ground water is withdrawn from one well, heated in a heat exchanger, and then returned to the same aquifer through the second well. The thermal energy is stored in the aquifer until needed. At recovery, the second well is pumped, and the hot water is circulated through a heat exchanger to recapture the stored energy which is then used for space or process heating, thus reducing the need for generating primary energy. The cycle is repeated on a seasonal or other time related basis. The concept is simple, inexpensive and relatively efficient.

- Insulated pond storage - ponds are excavated and constructed to specific dimensions and lined with an impermeable material. The lining serves to minimize loss of the storage medium and associated thermal energy. Insulation also covers the pond surface. This system may be economical on a large scale basis for both short term and seasonal storage durations.

- Natural pond and lake storage - the use of natural lakes or ponds for storage of thermal energy relies on the maintenance of a two-stage thermocline in the water. Preliminary concepts call for an insulated cover to be floated on the surface of these reservoirs. Hot water (95°C) would be stored in the upper layer of the lake, warm water (25 to 50°C) in a layer at mid-depth, and cold water (10 to 20°C) in the lower layer. Vertical insulated containment barriers anchored to the bottom of the lake have been suggested for separating the warm and hot layers. Technical questions regarding the thermal efficiency and hydrodynamic stability of this storage have received limited attention. The concept is economically attractive because it involves low construction outlays. Natural lakes or ponds may be found to be feasible for short or long storage duration. However, studies have not progressed beyond the conceptual and feasibility stages.

- Tank storage - large tanks have been considered in combination with several technologies as a means to store thermal energy. Tanks are usually fabricated out of reinforced concrete, fibreglass or steel, depending on temperature and corrosion requirements. Some tanks are lined or coated with plastic, rubber or other appropriate materials. Tanks can be made in sectional modules to reduce costs, but their lifetimes are hard to predict. Metal tank storage has been considered for applications in which temperatures less than 95°C, at high or low pressures, are anticipated. The technology for metal tank storage is well developed although, the projected cost, relative to other storage alternatives, remains high.

- Rock beds - are generally suitable for short duration storage, and their application for seasonal storage is being evaluated. The rock bed could be constructed in an excavated pit using air as the working fluid. Thermal energy could be stored in rock beds at much higher temperatures (without the attendant leakage problems) than in other seasonal storage media. For seasonal applications, the cost of materials handling and the purchase of the rock are serious considerations. Thermal stratification and air circulation within rock beds have received only limited analysis. Heat exchangers capable of handling air as a working fluid are necessarily larger and thus more expensive than those that use water.

- Solar ponds - solar ponds for both the collection and storage of solar energy are under development by U.S. Department of Energy (USDOE). Solar ponds store thermal energy in an insulated pond enclosed in an impermeable liner. The pond has a steep salt gradient to suppress thermal convection and to enhance storage capacity. To date, solar ponds have not been utilized for the storage of waste heat from power plants or industrial processes, but such applications are plausible. Solar ponds may be suitable for short or long duration storage.

- Wet earth storage - in this system heated air is circulated through plastic pipes embedded in a wet earth trench. The wet earth filled trench is lined with plastic as a moisture barrier and is insulated. Wet earth is a good medium for storage because:

  - the soil characteristics for wet earth storage are not critical;

- wet earth has considerably better heat-holding characteristics than rock;

- relative to several other storage alternatives (e.g. metal tanks or rock beds), capital costs are less;

- thermal storage in wet earth does not exclude other uses of the land.

Wet earth is feasible for short storage durations, but has not yet been tested as a seasonal storage system. However, it may be less feasible economically than aquifer or insulated pond storage.

Heat storage installations have been successful in Europe, and small scale projects and feasibility studies have also been investigated in the U.S. to a great extent.

At Kerava (60°N latitude), in Finland, a solar assisted heat pump with long term storage has been successfully utilized for 40 flats. The heating medium (water) is stored in a rock cavern. A conventional electric boiler serves as a backup heating system and also as a means of charging the storage system in late autumn to ensure it will be effective throughout the winter. The storage charging is done at that time to avoid electric power consumption during the wintertime peak loading of the electricity grid.

The total costs of the heating system exceed those of an average system by approximately 35%. The Kerava solar village is too expensive to be profitable although this is due in part to its experimental nature and purpose. However, it does illustrate that heat can be stored for long durations in northern climates.

In Canada, a study prepared by Acres Shawinigan Ltd. (16) examined the concept of the provision of district heating from a nuclear generating station to a new townsite (North Pickering, Ontario), by extracting heat during the electrical off-peak period and storing it as hot water in reservoirs for the day-round heating of the town. Compared to conventional DH schemes, the nuclear base load heating and storage with either fossil fuel or electric peak load heating systems were the most economically attractive.

638 ADVANCED COMBUSTION TECHNOLOGIES

Previous sections of this report have noted that, for DH stations which require production of steam, a number of fuels are feasible. The technologies for combustion of gas, oil, coal, lignite, wood, peat, and municipal waste are well-proven. Some of the advanced technologies currently under development are discussed in this section, as well as combustion technologies related to burning low-grade fuels in gas turbines and diesel engines.

.1 Fluidized Bed Combustion

Fluidized bed combustion is a system whereby fuel (generally high sulphur coal) is burnt on a sorbent bed (limestone and ash) which is fluidized by an upward flow of primary air. This method of burning coal limits the amount of sulphur dioxide (SO_2) emitted to the atmosphere, as the sulphur in the coal reacts with the limestone and is discharged. There are various types of fluidized bed combustors including:

- Atmospheric Fluidized Bed Combustor (AFBC) - compared to a pulverized coal boiler, the particle size is larger in the AFBC, coal residence time in the boiler is longer and flame temperature is lower. Longer time allows reaction of SO_2 gas and limestone. Nitrous oxides (NO_x) emissions are also reduced due to the lower flame temperature.

- Solids Recycling Atmospheric Fluidized Bed Combustor - in order to effect savings in both sorbent and fuel, relatively coarse size particles of coal elutriated from the bed are captured in hot dust collectors (precipitators) and fed back into the carbon burn up bed for secondary carbon combustion. Overall combustion efficiencies of 95 to 99 percent can be obtained for recycle systems.

- Circulating Fluidized Bed Combustor - basically secondary air is admitted to the combustor at several levels to maintain gas velocity at a slightly higher rate than the particle falling velocity. This arrangement of staged secondary air admittance is a significant feature which distinguishes the circulating fluidized bed combustor from the solids recycling fluidized bed combustor. The aim is to achieve staged combustion so that NO_x emission can be lower than from the conventional AFBC. Additional reasons for pursuing circulating bed development include improved combustion efficiency, improved steam temperature and heat input control, improved shutdown/startup characteristics, less complex coal feed, improved calcium utilization and reduced bed area requirements.

- Pressurized Fluidized Bed Combustor (PFBC) - in this system, fluidized bed combustion takes place under several atmospheres of pressure; therefore, combustion air has to be compressed before entering the combustor. For the sake of effective energy conservation, PFBC technology is more suitable for combined cycle applications. The proponents of

PFBC technology have essentially split into two camps: those favoring the air heater concept with steam bottoming using a waste heat recovery boiler, and those favoring the steam boiler concept. Apparent advantages of PFBC may be summarized as follows:

- Due to compressed combustion air, a smaller bed size can be realized compared with an AFBC of the same steam output.

- Pressurized fluidized beds have reported higher combustion efficiencies, and may eliminate the requirement of grit recycling or a separate carbon burnup cell.

- Sulphur retention in dolomite sorbent is reportedly improved at increased pressure, thereby reducing the amount of sorbent required as limestone utilization apparently decreases at increased pressures.

- Reduction of NO_x emission is also reported at increased pressures.

- Ideal thermal efficiency of the combined-cycle technology can be increased due to full utilization of available heat energy at high temperature levels through a gas turbine.

The hot flue gas from the PFBC should be free of fly ash particulate contaminants prior to entering a gas turbine, in order to avoid erosion, corrosion, or deposition of solids on the turbine blades. The reliable removal of fly ash particulates from a hot pressurized gas stream, using conventional fabric filtration, has posed a difficult problem for the development of the pressurized fluidized bed combustor. An alternative concept of ceramic fabric filtration is in the developmental stage.

In short, PFBC in combination with a combined thermal cycle, has some advantages over the AFBC system in the aspects of cycle efficiency, NO_x/SO_2 pollutant control and compactness of the combustor. However, all the combined-cycle systems involving PFBC technology are still in the developmental stage.

Fluidized bed combustion development offers a good approach to burning low grade coal by capturing the sulphur dioxide as soon as it is formed in the coal combustion process.

As far as development of AFBC is concerned, figures cited by USDOE and private industry show 70 to 125 industrial fluid-bed systems sold, under construction or operating in the U.S. Of these, only about 30 to 40 burn coal, the fuel that most suppliers and buyers would like to see replace gas and oil. The remainder burn waste fuels such as wood chips or sludge. While fluid-bed systems have been tested extensively in the range of industrial application, namely boilers producing 0.32-70 kg/s of steam per hour, little work has been done in scaling these systems up for utility use.

The Tennessee Valley Authority (TVA) has dedicated a 20 MW atmospheric fluidized bed combustion (AFBC) pilot plant at Paducah, Kentucky. TVA also recently awarded a contract for a 160 MW unit to Combustion Engineering Co. Ltd. Other utility projects include plans for a 110 MW unit for Colorado-Ute Electric Association, and conversion of a conventional 85 MW unit to a fluidized bed in St. Paul. Design studies are being prepared in the U.S. for boiler sizes up to 800 MW.

In Canada, 2 x 40,000 lb/hr atmospheric fluidized bed boilers have been installed at Canadian Forces Base, Summerside, P.E.I. to supply steam for heating the air force base. These units have been commercial since 1982, and for the past two heating seasons have provided base heating requirements.

In summary, fluidized bed boilers are proving to be an economical alternative to limit environmental impact, as opposed to conventional boilers with flue gas desulphurization when burning low grade coal.

.2 Coal Liquid Mixtures (CLM)

The development of coal-oil mixtures (COM) and coal-water mixtures (CWM) has been actively pursued in Europe and North America since the early 1970's as a means of reducing fuel oil firing. CLM may provide an economical means of extending the life of existing oil-fired boilers, especially where full conversion to coal would impose a substantial derating and high conversion cost. Coal liquid mixtures would reduce sulphur dioxide emission to some degree, particularly since advanced fine size physical coal cleaning processes would be involved in the preparation of the coal liquid mixtures.

CLM has been demonstrated in many test facilities and pilot plants in both Europe and North America and commercial operation of large utility and industrial boilers is close to realization.

In Canada, a test program supported by EM&R, the New Brunswick Electric Power Commission (NBEPC) and Cape Breton Development Corporation (CBDC) is demonstrating the preparation of CWM and its utilization in utility boilers. The major objectives of the project are to build a 4 t/h CWM pilot plant, based on a Swedish process known as Carbogel, in Sydney, Nova Scotia. Burners were also developed and tested in the 12.5 MW(e) unit No. 1 front-wall fired boiler and in the 22 MW(e) tangentially fired balanced draft unit No. 2 at the Chatham, New Brunswick generating station. As of April 1984, baseline oil tests had been completed on Unit No. 1 and 10 MW(e) was selected as the full load on the unit. Tests on Unit No. 2 were still in progress.

Further efforts of the program include selection and testing of burners in a 20 MW(e) oil-designed front-wall fired boiler located in Charlottetown, Prince Edward Island and operated by Maritime Electric Company. Following the Chatham and Charlottetown demonstration the third phase of the program will be a design of burners and test in the 50 to 150 MW(e) range.

In selecting candidate steam generators most suitable for conversion to CLM firing, the following criteria must be carefully evaluated:

- Capital cost of all CLM support equipment, including any steam generator modifications.
- Increase in operating and maintenance costs.
- Remaining life of the rest of the plant equipment.
- Change of steam generator availability due to an increase in forced outage rate.
- Derating penalty.
- Change in unit heat rate, caused by a decrease in steam generator thermal efficiency.
- Environmental impact.

Generally speaking, the economic feasibility of CLM is dependent on the differential in cost between CLM fuel and fuel oil. International Energy Agency (IEA) has studied the cost of CWM and has estimated the following comparison with residual fuel oil (RFO).

TABLE 6-28

The Cost of CWM
(1984 Canadian $) (209)

		Low	High
Coal, including delivery	($/t coal)	57.60	83.20
CWM preparation	($/t CWM)	32.00	44.80
Coal recovery in cleaning	(%)	95	90
CWM transport	($/t CWM)	6.40	6.40
Total	($/t CWM)	83.60	121.40
	($/GJ)	3.65	5.28
Price of RFO	($/GJ)	6.40	5.76
Fuel Price Differential	($/GJ)	2.75	0.48

Based on estimated costs for boiler modifications, boiler derating, O&M and other costs, IEA estimated the following load factors of boilers for 2 year payback.

TABLE 6-29

Average and Required Boiler Load Factors (209)

Size Range MW(e)	No. % of Total Population*	Average Load Factor %*	Load Factor Required for 2 Year Payback at a Price Differential ($/GJ) of:			
			0.65	1.30	1.95	2.60
15-29	44	33	100 +	82	53	39
30-73	40	40	100 +	75	48	35
74-146	12	53	100 +	68	44	32
147	4	59	100 +	61	39	29

* For the U.S. (1979).

Based on the differential in cost between CWM and oil, it is evident that a price differential approaching \$2/GJ is required for average boiler load factors to make CWM economically attractive.

In addition to firing coal liquid mixtures in steam generators, research is also being conducted into firing coal water mixtures in combustion engines. Supported by the Morgantown Energy Technology Center of the USDOE, Westinghouse Electric Corporation have tested CWM in a low emission staged rich-lean combustor while meeting EPA emission standards for stationary combustion turbines. The burner tested was a Multiannular Swirl Burner (MASB) which utilizes the rich-lean process to minimize NO_x from the combustion of nitrogen-bearing fuel such as coal derived liquids or coal water mixtures. The MASB has attractive potentials for further development.

Research, also supported by USDOE, is in progress for CWM firing of diesel engines. An experimental direct injection diesel engine operating at 900 rpm, without any combustion assisting mechanisms except preheating the inlet air, has been tested. The two principal technical problem areas in the operation of a diesel engine on coal-water slurry are the fuel injection and combustion, and the wear on the cylinder rings, liners, and other engine components.

The test program indicates CWM firing of a diesel to be a future possibility for oil replacement.

In summary, even though not yet commercial, CLM is a feasible alternative to burning oil in steam generating facilities without suffering substantial output derating. Firing of CLM in combustion engines seems technically feasible, however, the development is still in the early stages.

.3 Coal Gasification

Coal gasification is one of the alternative methods for atmospheric sulphur/nitrogen pollutant control. In general, feedstock coal, in combination with steam and oxygen (or air) is converted to raw product gas containing major enthalpy valued species such as CO, H_2 and CH_4. The concentration of each of these species depends mainly on the gasification process selected. The raw gas then undergoes a purification process to become clean combustible synthetic gas.

Fundamentally, steam is used as the source for producing hydrogen and hydrocarbons in the synthetic gas. The major sulphur pollutant in the gasification process is hydrogen sulphide, as opposed to sulphur dioxide from conventional boilers. During the purification process, H_2S is removed in an amine or a carbonate absorber and the used reagent is usually regenerated for recycling.

It is evident that the operating temperature in a coal gasifier is relatively low compared with conventional boiler temperatures, and also that the gasification process must take place under a strong reducing atmosphere. Thus NO_x emission should not cause any problem in coal gasification. In cases where high or medium heating value synthetic gas is to be produced, the formation of thermal NO_x can be completely eliminated by using oxygen as the feedgas.

When the cleaned synthetic fuel gas is introduced in downstream applications, such as burning in gas turbines for combined cycle power generation or burning in boilers for direct steam generation, thermal NO_x will regenerate in the combustion system due to atmospheric nitrogen fixation. The investigation of gaseous fuel combustion control for NO_x emission is beyond the scope of the present study for coal combustion modifications. Nevertheless, it can be stated that the fuel gas induced NO_x emission will be far less than that induced from coal combustion.

A considerable number of coal gasification processes and combined cycle power generation systems can be considered either commercially available or at the developmental stage. Estimates suggest that integrated gasification combined cycle (IGCC) plants could be built cost effectively in module increments of about 250 MW(e).

.4 Coal-Fired Gas Turbines

The technology of burning coal in gas turbines has been investigated for decades. However, with the current wide differential in the price of coal compared to oil, USDOE's Morgantown, West Virginia Energy Technology Center awarded three projects in 1983 aimed at developing an electricity generating plant based on a coal-fired gas turbine. Two of the projects are to conduct analytical studies on at least two coal-based fuel forms such as coal water mixtures or fuel gas from coal. The other project is to determine how coal might be used to power gas turbines in the future. Hopefully these current programs will help decide whether research should be aimed at strengthening the gas turbines so they can burn a dirty fuel like coal, or whether the coal should be cleaned until it is suitable for gas turbines, or some combination of these.

Some of the problems of burning coal in gas turbines are turbine blade erosion, corrosion, ash particle deposition, and high nitrogen oxides emission. DOE report that approaches to overcoming these problems include: a) cleaning the coal fuel to acceptable levels to remove the offending contaminants; b) modifying the turbines through the use of new materials, application of cooling techniques, different methods of construction, or by changes in physical configuration; and c) remove contaminants during or immediately after combustion.

In order to directly fire coal in a gas turbine fine grinding to 1-3 micron particle size is required. Methods for grinding coal more finely, ways of separating contaminants from the finely-ground coal, and promising work on burning the coal in a liquid-like mixture with water are examples of fairly recent developments.

DOE report that an economic analysis shows an advantage for a gas turbine-based combined-cycle power plant burning a coal-water mixture even if it requires flue-gas cleaning equipment. Such a plant could have a heat rate of 9125 kJ/kWh and would cost 32 percent less than a conventional coal-fired plant.

Even though still in the developmental stage, this technology may prove beneficial in the near future.

639 FUEL CELL POWER PLANTS

Fuel cell power plants (FCPP), a recent developing technology, utilize an electrochemical device which converts a hydrocarbon fuel to electricity, without combusting the fuel. As illustrated in Figure 6-24, the FCPP is comprised of three main sections:

- A fuel processor which converts hydrocarbon fuels into purified hydrogen rich fuel suitable for use in the fuel cell stacks.

- Power section to convert hydrogen into direct current electricity. The design of each cell comprises an

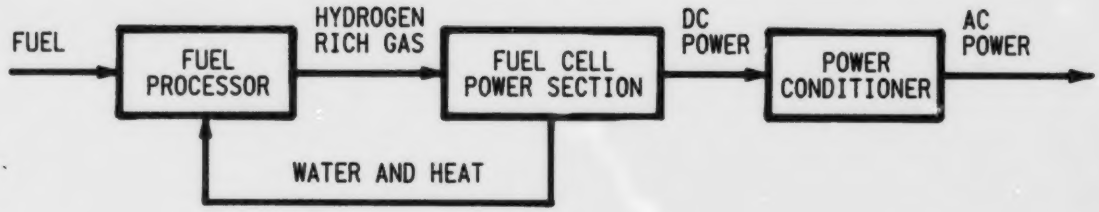

FUEL
FUEL PROCESSOR
HYDROGEN RICH GAS
FUEL CELL POWER SECTION
DC POWER
POWER CONDITIONER
AC POWER
WATER AND HEAT

FIGURE 6-24
FUEL CELL POWER PLANT

electrolyte held in a matrix between two electrodes coated with a catalyst. Each cell produces electricity and, when connected in series, the cells form fuel cell stacks.

- Power conditioner to convert the direct current power to alternating current power, which is compatible with the utility grid.

Of the many types of fuel cells under investigation, the one which is closest to commercialization is the phosphoric acid fuel cell. In 1977, United Technologies Corporation (UTC) demonstrated a 1 MW(e) prototype unit at their manufacturing facility in Connecticut. UTC also successfully demonstrated 4.5 MW(e) plants in Tokyo and New York City. UTC expect to have two or three 11 MW(e) commercial prototypes in the field by 1987. Westinghouse has similar goals for a 7.5 MW(e) unit.

Features of the FCPP which make it attractive for utilities include modular construction, short construction lead time, siting flexibility, high efficiency over a relatively wide load range, fuel flexibility, environmental compatibility, rapid load response capability, cogeneration potential, reliability and capability for remote (unmanned) operation.

An additional feature of the FCPP which makes it suitable for application in district heating systems is that heat is rejected in the form of pressurized hot water and saturated steam. The reject heat from a phosphoric acid fuel cell is expected to be in the form of 82°C water and saturated steam at 415 kPa. Another type of fuel cell, the molten carbonate type, is expected to reject heat at a temperature over 590°C. This may allow further electricity production in a steam turbine/generator set (steam topping) cycle prior to the use of waste heat for district heating.

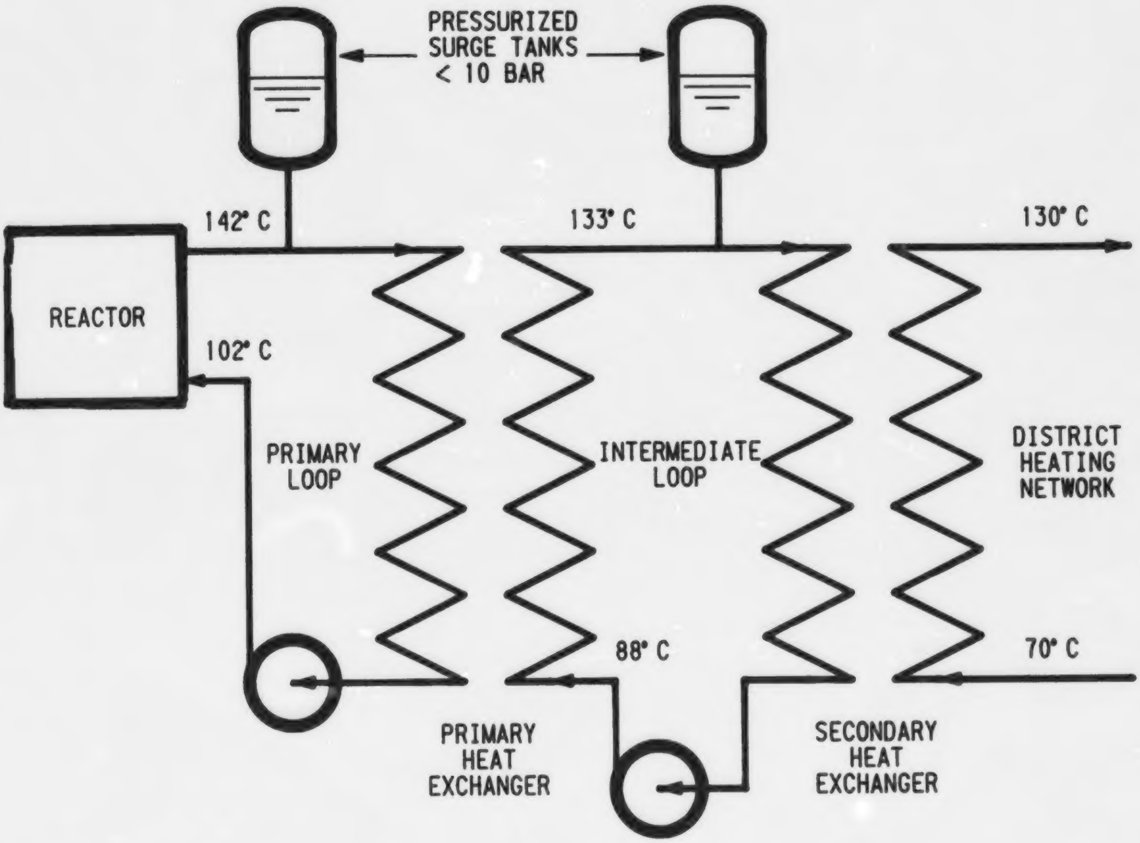
6310 SMALL NUCLEAR REACTORS

Small nuclear reactors may be feasible to supply heat for district heating systems. The following two subsections describe potentially suitable reactors.

.1 Small TRIGA Power Reactors

GA Technologies Inc. (GA) (90) is expanding its TRIGA reactor product line to include small power reactors of up to 53 MW(t) for district heating. This development was made economically viable by the increased costs of fossil fuel relative to uranium fuel. The highly successful operation of the largest TRIGA, the 15 MW(t) reactor at the Institute for Nuclear Power Reactors in Pitesti, Romania, has demonstrated the high-powered fuel element design that is proposed for the TRIGA power reactor core.

The proposed TRIGA reactor primary and secondary coolant system configuration for district heating is illustrated in Figure 6-25. The primary system is composed of a reactor module and a heat exchanger module. These modules are vertically oriented in below-grade steel-lined pits to provide a convenient means of radiation shielding as well as to maintain a low building profile. An intermediate loop, consisting of heat exchanger, surge tank, pump and piping is provided to isolate the reactor system from the district heating network. The modules, pressurizer service systems and interconnecting piping are factory assembled, instrumented, and pretested to minimize site construction time.


PRESSURIZED SURGE TANKS < 10 BAR
142° C
133° C
130° C
REACTOR
102° C
PRIMARY LOOP
INTERMEDIATE LOOP
DISTRICT HEATING NETWORK
88° C
70° C
PRIMARY HEAT EXCHANGER
SECONDARY HEAT EXCHANGER

[100,77]DSS625 .DGN

FIGURE 6-25
TRIGA POWER REACTOR SYSTEM
CONFIGURATION FOR DISTRICT HEATING

Refuelling can be accomplished by replacing either half the core every 30 full-power months, or the complete core every 60 full-power months. Because district heat reactors may, at most, attain an average load factor of about 50%, a batch loaded core may last for about 10 years without any refuelling. The simplified design enables completion of refuelling within a few days.

The reactor core uses standard TRIGA UZrH eutectic alloy fuel, which is cast in cylindrical billets 12.9 mm in diameter by 139.7 mm long. This fuel has two important advantages for small power reactor operation. One is inherent safety against reactivity accidents. The other is the unusually high fission product retention capability of the fuel material.

A major design objective of GA's small power reactor program is to retain TRIGA's passive, inherent design safety features, which prevent or mitigate the effects of accidents or transients. This approach not only eliminates the need for complex engineered safety systems, but also makes it possible to contemplate automated, unattended reactor operation.

Two heat exchangers are required for a reactor driven DH system; one for isolation of the primary circuit and the other to transfer the heat from the isolation circuit to the district heating distribution circuit. The recommended heat exchanger design is the rod baffle type with axial flow on the shell side as well as the tube side so that the heat transfer is accomplished in a pure counterflow arrangement.

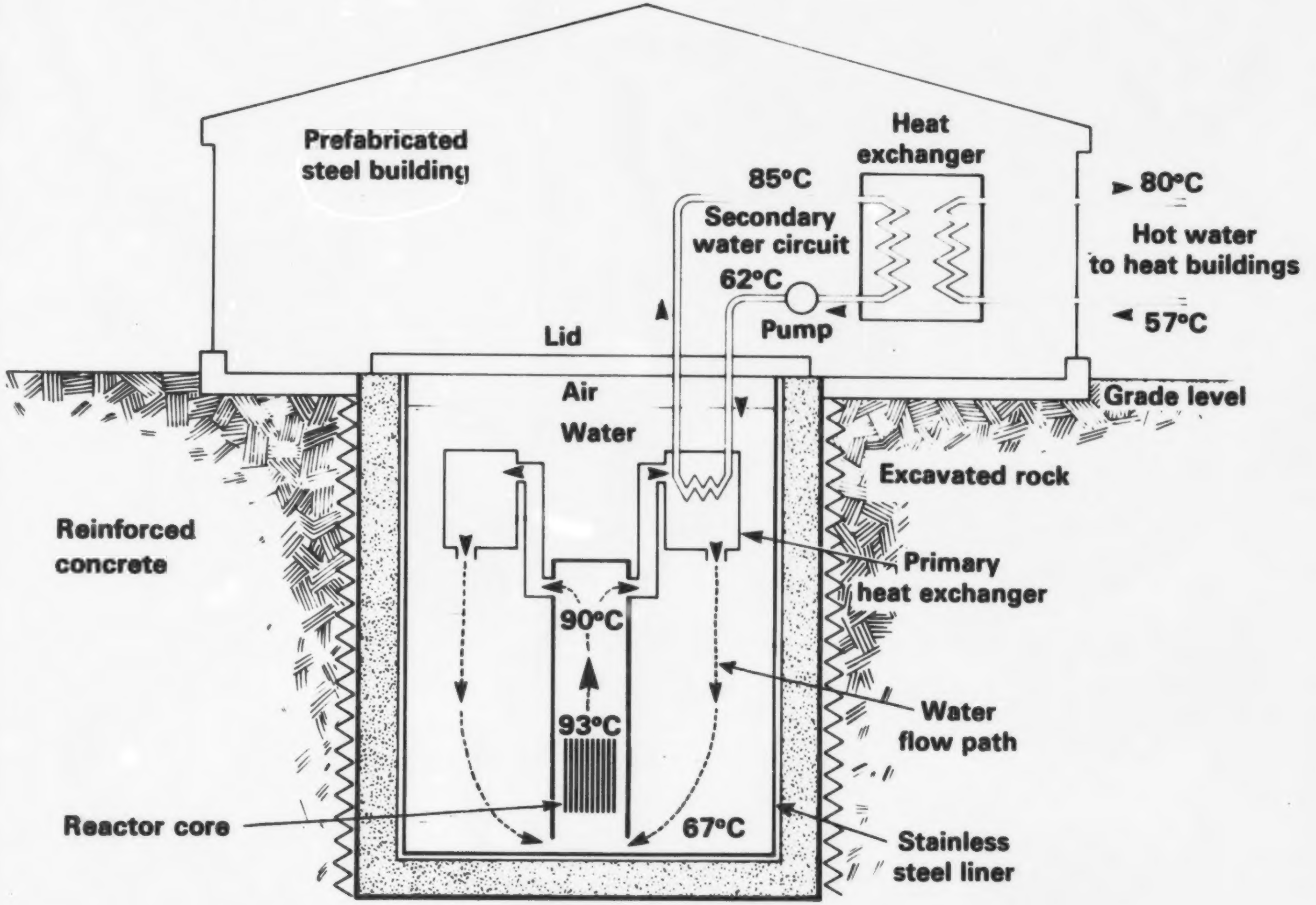
Another feature of the small TRIGA power reactor system is its ability to generate electricity in addition to sensible heat for local district heating networks. This may be an attractive application of the TRIGA power reactor in certain geographic and economic environments.

GA has completed the conceptual design of a small TRIGA power reactor with a capacity of 53 MW(t) for use in district heating networks. This work shows that any reactor size with a power between 10 and 53 MW(t) is feasible and that the inherent safety features of the TRIGA reactor concept can be maintained. Prospects for the small TRIGA power reactor for use in district heating networks are excellent. The technology has been well demonstrated and the economics at this stage look favourable. Public acceptance and licencing issues associated with siting of small nuclear units in high population areas are possible barriers. But GA has designed the small TRIGA power reactor to be literally "walk-away" safe. The simplified design, combined with operating experience from over 60 TRIGA research reactors, should significantly diminish any initial resistance to, and the cost of, the first commercial unit.

.2 SLOWPOKE Reactors for Community Heating

SLOWPOKE is an acronym for Safe Low Power Critical (K) Experiment, a small nuclear reactor first designed as a research tool by Atomic Energy of Canada Limited (AECL) (101). Slowpoke-2, a 20 kW thermal capacity unit, was developed from the initial design, and six of these reactors have been installed in Canadian cities. They are licensed to operate unattended, but remotely monitored, for periods up to 24 hours. The low temperature operation leads to simplicity, safety and low cost. The six units so far installed have acquired about 30 reactor-years of operating experience. This has encouraged AECL to develop a design for Slowpoke-3, a heating reactor of 2 MW thermal capacity, illustrated in Figure 6-26.

3718-K


Prefabricated steel building
Heat exchanger
85°C
Secondary water circuit
62°C
Pump
80°C
Hot water to heat buildings
57°C
Lid
Air
Water
Grade level
Excavated rock
Reinforced concrete
Primary heat exchanger
90°C
93°C
Water flow path
Reactor core
67°C
Stainless steel liner

SLOWPOKE HEATING REACTOR

FIGURE 6-26

It will be seen from the drawing that the Slowpoke-3 secondary water loop isolates the building water heating system from the water in the reactor pool.

A decision was taken by AECL in 1984 to produce the first 2 MW Slowpoke-3 prototype unit at an estimated cost of about $4.5 million. It is estimated that subsequently these units could be built commercially at a cost of about $400 to $500 per thermal kW.

Whereas the existing Slowpoke-2 reactors use uranium fuel enriched to 93%, the Slowpoke-3 will use fuel enriched only to 5%.

The 2 MW Slowpoke-3 prototype is scheduled for startup in 1986. If successful, the long term program calls for upgrading in commercial sizes ranging 2 MW to 20 MW in order to take advantages of benefits of scale. While the 2 MW unit is estimated to be competitive with oil-fired heating in remote regions of Canada, where heating oil has to be flown in, unit sizes of 5 MW+ are expected to compete with heating by natural gas in most regions of Canada.

A Super-Slowpoke unit is also being designed, operating at higher mean temperatures, for coupling with an organic Rankine cycle system for generation of electrical energy. AECL estimate that such a system could generate electrical power in some remote Canadian communities at lower costs than are currently possible there using fossil fuels. If this should materialize, the system could also operate in a cogeneration mode, producing both the heating and electrical power requirements of remote communities.

The Slowpoke reactor is expected to produce heat at a cost that is less than or comparable to fuel oil - or $.04/kWh based on a Toronto installation. The $.04/kWh price includes all costs and is in effect the price that would be charged by the facility owner in order to meet his financial obligations.

The reference parameters of Slowpoke - 3 are given in Table 6-30.

TABLE 6-30

Reference Parameters of SLOWPOKE-3

Thermal power (MW(th))	2.00
Core height (cm)	49.53
Core diameter (cm)	30.00
Number of fuel elements	193
Outside diameter of fuel elements (cm)	1.31
Mass of UO_2 (kg)	111.4
Uranium enrichment (%)	5
Average fuel burnup (MW d kg^{-1})	11.2
Core lifetime (MW/a)	3.0
Average heat flux (W/cm^2)	50.9
Maximum heat flux (W/cm^2)	89.1
Mass flow rate through core (kg/s)	15.7
Core outlet pressure (kPa)	170
Core inlet temperature (°C)	67.2
Core outlet temperature (°C)	92.7
Heat exchanger inlet temperature (°C)	90.0
Building heating water - supply temperature (°C)	80
- return temperature (°C)	57
Building length (m)	18.3
Building width (m)	15.5
Building height (m)	7.7

Operating costs will be practically non-existent with AECL entirely responsible for refuelling and decommissioning.

The costs of fuel, operating, maintenance, refuelling and decommissioning are included in the $.04 calculation.

Component prices are being finalized in 1985 and will be made available to customers with serious applications opportunities.

The unit has a minimum expected lifetime of twenty years, with refuelling occurring annually (dependent upon the level of heat demand at the particular location). Refuelling is estimated to involve downtime of one week for the unit.

Availability of the unit lies in he 1987 to 1989 timeframe. Lead time is expected to be one to two years.

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* The exact price will vary dependent upon unit size and load factor.

6.4 SPECIFIC COSTS

641 GENERAL

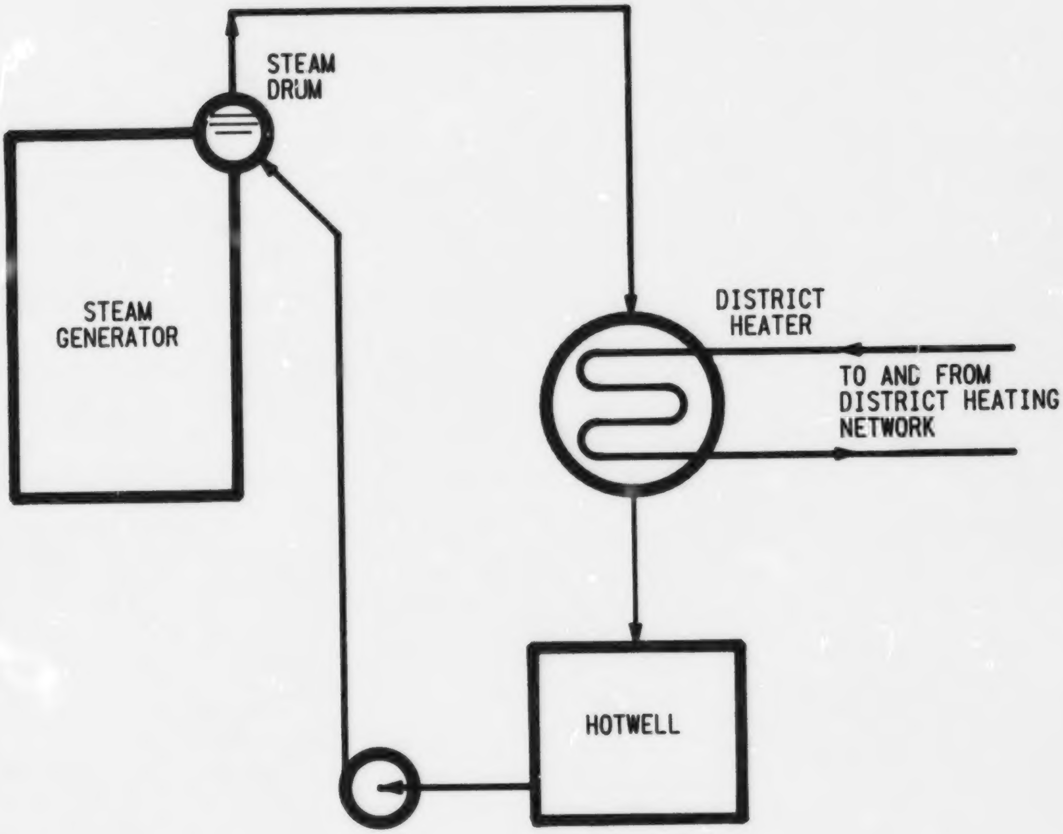
It is evident from the descriptions of the system options in the previous section that the selection of a district heating plant is very site specific and an extensive optimization analysis would be required to determine the most suitable system for each case. An optimization analysis is beyond the scope of this general study. To estimate the specific costs of producing heat for the selected Canadian sites, it was therefore necessary to select suitable system options.

For purposes of this study, the following two systems are evaluated:

a) Heat Only Station - utilizing low pressure steam generators and district heaters. A schematic of this unit is illustrated in Figure 6-27.

b) Cogeneration Station - Unit to consist of a high pressure boiler with an extraction turbine to provide base load heat, and a low pressure boiler to provide peak load heat. A schematic of this unit is illustrated in Figure 6-28. Even though an extraction turbine system is initially more expensive than a backpressure turbine system, the operation of the extraction system is more flexible due to the variable relationship between the generation of heat and electrical power, and was therefore selected for this study.

The operating and cost data have been derived for both the heat only and cogeneration plants due to the fact that discharging


STEAM DRUM
STEAM GENERATOR
DISTRICT HEATER
TO AND FROM DISTRICT HEATING NETWORK
HOTWELL

[100,77]DSS627 .DGN

FIGURE 6-27
HEAT ONLY UNIT

[100,77]DSS628 .DGN

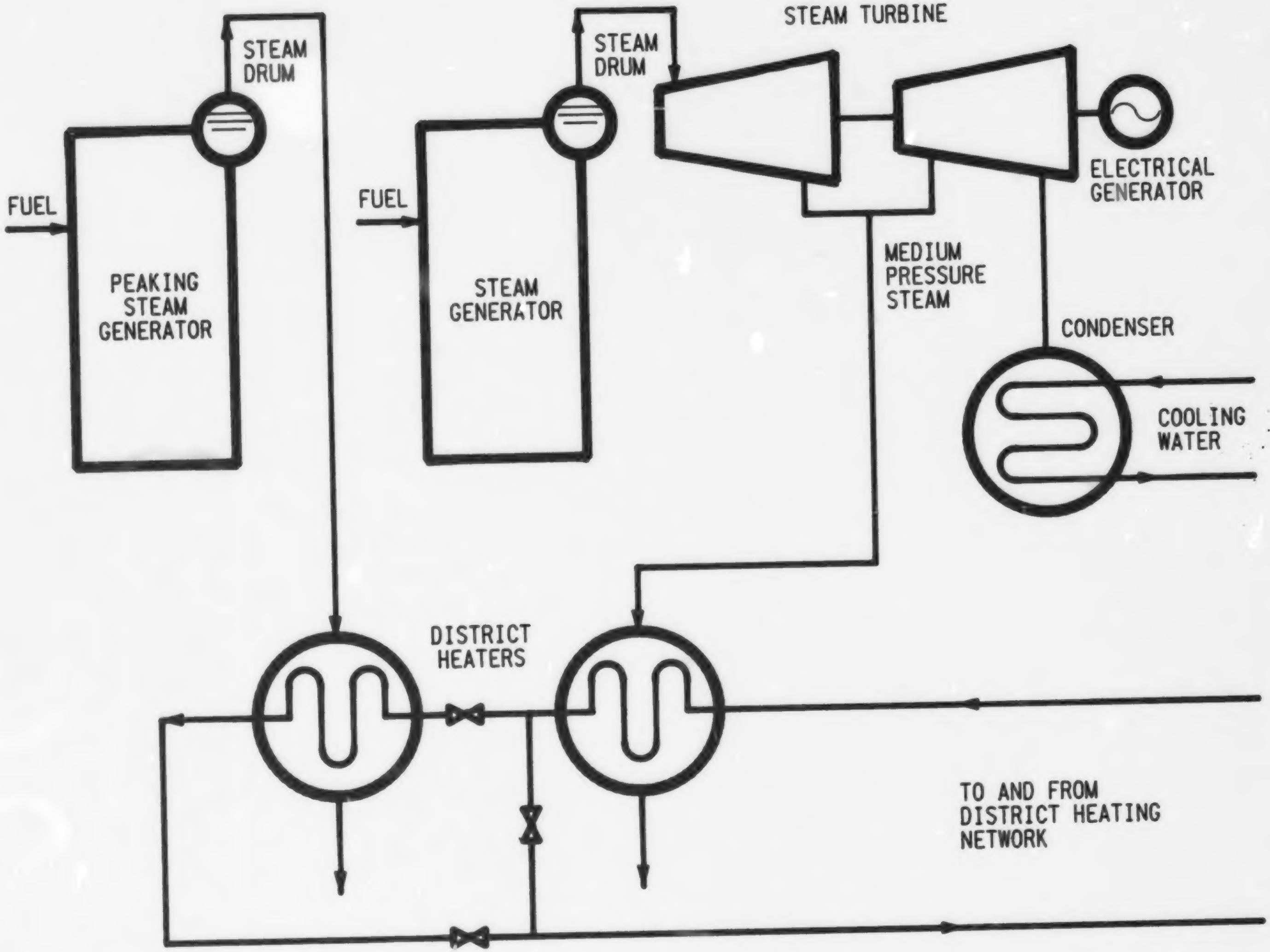

STEAM DRUM
FUEL
PEAKING STEAM GENERATOR
STEAM DRUM
FUEL
STEAM GENERATOR
STEAM TURBINE
ELECTRICAL GENERATOR
MEDIUM PRESSURE STEAM
CONDENSER
COOLING WATER
DISTRICT HEATERS
TO AND FROM DISTRICT HEATING NETWORK

FIGURE 6-28
SCHEMATIC OF EXTRACTION TURBINE
STEAM TOPPING CYCLE
WITH PEAKING BOILER

surplus electricity to a utility can be a problem both politically and economically, depending on which area of the country is being considered. Since many utilities are currently in an excess generation capacity situation, they may not be willing to accept additional power from a DH system. Therefore a heat only plant should be considered as the main arrangement for supplying heat to the network.

642 DISTRICT HEATING STATION SIZE AND PERFORMANCE

Since the DH station size is site dependent, performance and economic analyses were estimated for four plant sizes. Each plant comprises 4 x 33.3% of full load capacity units as follows:

- 4 x 6 MW_t units to provide 18 MW_t station capacity
- 4 x 50 MW_t units to provide 150 MW_t station capacity
- 4 x 100 MW_t units to provide 300 MW_t station capacity
- 4 x 500 MW_t units to provide 1500 MW_t station capacity

These station sizes were selected so that representative points were available to prepare graphs (Figures 6-29 and 6-30) which provide the cost of heat for a wide range of district heating systems. The 1500 MW_t station is currently unrealistic for Canada since it is capable of heating 125,000 houses, or about 60% of the houses in the city of Toronto. Perhaps the most realistic station size is 240-360 MW_t (20-30,000 houses) which is the common size for European stations.

For the heat only stations, the 6 MW_t, 50 MW_t, and 100 MW_t unit capacities could be handled by a single boiler. However, for the 500 MW_t unit capacity, two boilers are required to meet the heat output.

It should be noted that a 250 MW_t (860,000 lbs/hr) low pressure boiler is not a standard design and supply item, but there are no technical reasons to prevent such a size being supplied.

For the cogeneration stations, each unit includes a boiler and extraction turbine-generator set which provide base load heat and power plus a peaking boiler with equivalent heat output capacity of the extraction turbine. Therefore, the units consist of the following:

- 3 MW_t boiler and extraction turbine plus 3 MW_t peaking boiler for the 6 MW_t unit;
- 25 MW_t boiler and extraction turbine plus 25 MW_t peaking boiler for the 50 MW_t unit;
- 50 MW_t boiler and extraction turbine plus 50 MW_t peaking boiler for the 100 MW_t unit;
- 250 MW_t boiler and extraction turbine plus 250 MW_t peaking boiler for the 500 MW_t unit.

For these stations, the full range of sizes was also computed for comparison purposes, although not all sizes are practical, as the 4 x 6 MW_t station is small for cogeneration. For efficient cogeneration the boiler must be able to operate at 4137 kPag (600 psig) pressures or higher, and this requires water tube boilers. However, at 6 MW_t (20,000 lbs/hr) there are no suitable water tube boilers on the market, the smallest unit available being about 9 MW_t (30,000 lbs/hr). Furthermore, with cogeneration, the station requires qualified stationary engineers, while, if only hot water was generated, the requirements would be significantly reduced. In Europe, and particularly in Germany, this size of DH system usually has unattended hot water boilers. Aside from the steam generating facilities, extraction turbines of this size (1 MW_e) are extremely expensive.

As noted at the beginning of this part of the study, an optimization analysis would be required to determine the most suitable means of supplying heat for each district heating application. For smaller DH systems operating on oil or gas, a diesel engine with peaking boilers would be more appropriate if cogeneration is desired. The advantages include lower capital cost, automatic unattended operation, and a higher overall efficiency.

For calculation of the annual heat loads, the heat load curve illustrated in Figure 6-4 was utilized. For a heat only station, the number of boilers required to efficiently follow the heat load are placed in operation. Since standby boilers are provided, at least one boiler is idle at all times.

For the cogeneration station, each baseload boiler and extraction turbine operates at 100% MCR for 6570 hours per year (3/4 x 8760 hours). Steam is extracted from the turbine to meet the requirements of the district heating system. The extraction turbines provide 83.3% of the annual heating requirement and the remainder of the steam is used to produce electricity. It is assumed in this study that all of the electricity generated can be utilized by the grid system of the region. Based on the manufacturer's published data and power plant turbines installed in recent years, the following electrical outputs for the various size units were calculated and are indicated in Table 6-31.

TABLE 6-31

Electrical Output from Extraction Steam Turbines

Base Load Heating Capacity MWt	Electrical Output MWe	
	At Full District Heating Load	No District Heating Load
3 MWt	0.78	1.0
25 MWt	8.5	11.5
50 MWt	28.0	35.0
250 MWt	197.0	230.0

Each peaking boiler operates a maximum of 1725 hours (3/4 x 2300 hours) at a capacity to meet the winter peak demand as illustrated in Figure 6-4. The peaking boilers provide 17.7% of the annual heating requirement.

The annual operating data and costs for the heat only stations are summarized in Table 6-32. The annual operating data for the cogeneration station are summarized in Table 6-33 and the cost data in Table 6-34.

It should be noted that the cost of electricity for the heat only plants is included in Table 6-32. However, revenue from sales of net electric generation for cogeneration stations is not included in Table 6-34.

The unit cost results from Tables 6-32 and 6-35 are graphed in Figures 6-29 and 6-30 to allow estimation of costs for intermediate station capacities.

In order to illustrate the operating efficiency of the cogeneration units, Figures 6-31 through 6-32 graph net thermal efficiency (for various fuels) vs. the unit size for the cases of 100% district heating load and 0% district heating load. Efficiency for partial heating loads could be interpolated from the two curves.

The derivation of cost data presented in Tables 6-32 and 6-35 is discussed in the following sections.

TABLE 6-32

Heat Only Station - Summary of Annual Operating & Cost Data

UNIT SIZE	FUEL	ANNUAL HEAT PRODUCTION GJ x 10^3	TOTAL CAPITAL COST \$ x 10^6	ANNUAL O & M COST \$ x 10^6	ANNUAL FUEL CONSUMPT. GJ x 10^3	ANNUAL ELECTRICITY CONSUMPTION kWhr x 10^6	ANNUAL ELECTRICITY COST (@ \$0.026/kWhr) \$ x 10^6
18 MW_t	GAS	213.28	4.62	0.092	270	0.495	0.013
	OIL		5.132	0.103	260	0.495	0.013
	COAL		15.336	0.307	281	0.742	0.019
	WOOD, BIOMASS		20.704	0.414	328	0.824	0.021
	PEAT		23.772	0.475	328	0.824	0.021
	MSW		28.800	0.576	328	0.824	0.021
150 MW_t	GAS	1777.6	18.684	0.374	2116	4.121	0.107
	OIL		20.760	0.415	2020	4.121	0.107
	COAL		76.800	1.536	2116	6.181	0.161
	WOOD, BIOMASS		96.000	1.92	2250	6.868	0.179
	PEAT		111.360	2.227	2370	6.868	0.179
	MSW		156.000	3.12	2540	6.868	0.179
300 MW_t	GAS	3553.56	35.100	0.527	4230	8.242	0.214
	OIL		39.000	0.585	4038	8.242	0.214
	COAL		112.260	1.684	4230	12.362	0.321
	WOOD, BIOMASS		122.364	1.835	4498	13.736	0.357
	PEAT		151.552	2.273	4738	13.736	0.357
1500 MW_t	GAS	17774.4	136.680	2.05	21160	41.207	1.071
	OIL		151.800	2.277	20198	41.207	1.071
	COAL		402.000	6.03	21160	61.811	1.607

NOTE - Stations are comprised of the following: 18 MW_t = 4 x 6 MW_t Units
150 MW_t = 4 x 50 MW_t Units
300 MW_t = 4 x 100 MW_t Units
1500 MW_t = 8 x 250 MW_t Units

TABLE 6-33

Cogeneration Station - Summary of Annual Operating Characteristics

STATION SIZE	FUEL	ANNUAL HEAT PRODUCTION FOR DISTRICT HEATING GJ x 10^3	ANNUAL FUEL CONSUMPTION GJ x 10^3		GROSS ANNUAL ELEC. GEN. KWhr x 10^6 (GJ x 10^3)	ANNUAL ELECTRICAL CONSUMPTION BY COGENERATION SETS		ANNUAL ELECTRICAL CONSUMPTION BY PEAKING BOILERS		NET ANNUAL ELECTRICAL GENERATION		TOTAL NET ANNUAL STATION OUTPUT GJ x 10^3
			CO-GEN SETS	PEAKING BOILERS		kWhr x 10^6	GJ x 10^3	kWhr x 10^6	GJ x 10^3	kWhr x 10^6	GJ x 10^3	
18 MW_t	GAS/GAS	213.28	604.304	53.2	22.704	1.183	4.259	0.088	0.317	21.433	77.16	290.44
	OIL/OIL		574.088	50.8	(81.736)	1.183	4.259	0.088	0.317	21.433	77.16	290.44
	COAL/GAS		656.1	53.2		1.840	6.624	0.088	0.317	20.776	74.795	288.075
	COAL/OIL		656.1	50.8		1.840	6.624	0.088	0.317	20.776	74.795	288.075
	WOOD/BIOMASS/GAS		706.568	53.2		2.102	7.567	0.088	0.317	20.514	73.852	287.132
	WOOD/BIOMASS/OIL		706.568	50.8		2.102	7.567	0.088	0.317	20.514	73.852	287.132
	PEAT/GAS		706.568	53.2		2.102	7.567	0.088	0.317	20.514	73.852	287.132
	PEAT/OIL		706.568	50.8		2.102	7.567	0.088	0.317	20.514	73.852	287.132
	MSW/GAS		706.568	53.2		2.102	7.567	0.088	0.317	20.514	73.852	287.132
	MSW/OIL		706.568	50.8		2.102	7.567	0.088	0.317	20.514	73.852	287.132
150 MW_t	GAS/GAS	1777.6	4831.2	410.8	253.6	13.600	48.96	0.731	2.632	239.269	861.368	2638.968
	OIL/OIL		4606.5	394.4	(912.96)	13.600	48.96	0.731	2.632	239.269	861.368	2638.968
	COAL/GAS		4890.8	410.8		21.155	76.158	0.731	2.632	231.714	834.170	2611.77
	COAL/OIL		4890.8	394.4		21.155	76.158	0.731	2.632	231.714	834.170	2611.77
	WOOD/GAS		5825.6	410.8		24.178	87.041	0.731	2.632	228.691	823.287	2600.887
	WOOD/OIL		5825.6	394.4		24.178	87.041	0.731	2.632	228.691	823.287	2600.887
	PEAT/GAS		5825.6	410.8		24.178	87.041	0.731	2.632	228.691	823.287	2600.887
	PEAT/OIL		5825.6	394.4		24.178	87.041	0.731	2.632	228.691	823.287	2600.887
	MSW/GAS		5825.6	410.8		24.178	87.041	0.731	2.632	228.691	823.287	2600.887
	MSW/OIL		5825.6	394.4		24.178	87.041	0.731	2.632	228.691	823.287	2600.887

TABLE 6-33 (Cont'd)

Cogeneration Station - Summary of Annual Operating Characteristics

STATION SIZE	FUEL	ANNUAL HEAT PRODUCTION FOR DISTRICT HEATING GJ x 10^3	ANNUAL FUEL CONSUMPTION GJ x 10^3		GROSS ANNUAL ELEC. GEN. KWhr x 10^6 (GJ x 10^3)	ANNUAL ELECTRICAL CONSUMPTION BY COGENERATION SETS		ANNUAL ELECTRICAL CONSUMPTION BY PEAKING BOILERS		NET ANNUAL ELECTRICAL GENERATION		TOTAL NET ANNUAL STATION OUTPUT GJ x 10^3
			CO-GEN SETS	PEAKING BOILERS		kWhr x 10^6	GJ x 10^3	kWhr x 10^6	GJ x 10^3	kWhr x 10^6	GJ x 10^3	
300 MW_t	GAS/GAS	3553.56	10764.48	796	806.04 (2901.744)	41.391	149.008	1.461	5.260	763.188	2747.476	6301.036
	OIL/OIL		10275.2	765		41.391	149.008	1.461	5.260	763.188	2747.476	6301.036
	COAL/GAS		10764.48	796		64.386	231.790	1.461	5.260	740.193	2664.694	6218.254
	COAL/OIL		10764.48	765		64.386	231.790	1.461	5.260	740.193	2664.694	6218.254
	COAL/COAL		10764.48	796		64.386	231.790	2.192	7.891	739.462	2662.063	6215.623
	WOOD/GAS		11445.8	766		73.586	264.910	1.461	5.260	730.993	2631.574	6185.134
	WOOD/OIL		11445.8	795		73.586	264.910	1.461	5.260	730.993	2631.574	6185.134
	WOOD/COAL		11445.8	766		73.586	264.910	2.192	7.891	730.262	2628.943	6182.503
	PEAT/GAS		11445.8	796		73.586	264.910	1.461	5.260	730.993	2631.574	6185.134
	PEAT/OIL		11445.8	765		73.586	264.910	1.461	5.260	730.993	2631.574	6185.134
	PEAT/COAL		11445.8	796		73.586	264.910	2.192	7.891	730.262	2628.943	6182.503
1500 MW_t	GAS/GAS	17774.4	58414.	3982.4	5508.44 (19830.384	271.998	979.193	7.306	26.302	5229.136	18824.889	36599.289
	OIL/OIL		55758.4	3832.		271.998	979.193	7.306	26.302	5229.136	18824.889	36599.289
	COAL/GAS		58414	3982.4		423.108	1523.189	7.306	26.302	5078.026	18280.893	36055.293
	COAL/OIL		58414	3832.		423.108	1523.189	7.306	26.302	5078.026	18280.893	36055.293
	COAL/COAL		58414	3982.4		423.108	1523.189	10.959	39.452	5074.373	18267.743	36042.143

NOTE: Total Stations Consist of following:

Station Size	=	Cogeneration Sets	+	Peaking Boilers
18 MW_t		4 x 3 MW_t/.78 MW_e (1 MW_e)		4 x 3 MW_t
150 MW_t		4 x 25 MW_t/8.5 MW_e (11.5 MW_e)		4 x 25 MW_t
300 MW_t		4 x 50 MW_t/28 MW_e (35 MW_e)		4 x 50 MW_t
1500 MW_t		4 x 250 MW_t/197 MW_e (230 MW_e)		4 x 250 MW_t

Table 6-34

Breakdown of Cogeneration Station Performance

STATION SIZE	FUEL	ANNUAL HEAT PRODUCTION OF COGEN + PEAKING UNITS (TABLE 6-33)	ANNUAL POWER PRODUCTION (TABLE 6-33)	ANNUAL FUEL CONSUMPTION OF PEAKING BOILER (TABLE 6-33)	EFFICIENCY OF PEAKING BOILER (TABLE 6-32)	ANNUAL HEAT PRODUCTION OF PEAKING BOILER (4 X 5÷100)	ANNUAL HEAT PRODUCTION OF COGEN UNIT (2 - 6)	EFFICIENCY OF COGEN UNIT BOILER (TABLE 6-32)	ANNUAL FUEL CONSUMPTION OF COGEN UNIT			EFFICIENCY OF HEAT AND POWER PRODUCTION		
									FOR HEAT (7÷8 X 100)	FOR POWER (11 - 9)	FOR CHP (TABLE 6-33)	HEAT (8)	POWER (3÷10)	CHP (2+3÷11)
		GJ X 10^3	GJ X 10^3	GJ X 10^3	%	GJ X 10^3	GJ X 10^3	%	GJ X 10^3	GJ X 10^3	GJ X 10^3	%	%	%
0	1	2	3	4	5	6	7	8	9	10	11	12	13	14
18 MW$_t$	GAS/GAS	213.28	77.160	53.2	79	42.028	171.252	79	216.775	387.529	604.304	79	19.91	48.06
	OIL/OIL	213.28	77.160	50.8	82	41.656	171.624	82	209.298	364.790	574.088	82	21.15	50.60
	COAL/GAS	213.28	74.795	53.2	79	42.028	171.252	76	225.332	430.768	656.100	76	17.36	43.91
	COAL/OIL	213.28	74.795	50.8	82	41.656	171.624	76	225.821	430.279	656.100	76	17.38	43.91
	WOOD/BIOMASS/GAS	213.28	73.852	53.2	79	42.028	171.252	65	263.465	443.103	706.568	65	16.67	40.64
	WOOD/BIOMASS/OIL	213.28	73.852	50.8	82	41.656	171.624	65	264.037	442.531	706.568	65	16.69	40.64
	PEAT/GAS	213.28	73.852	53.2	79	42.028	171.252	65	263.465	443.103	706.568	65	16.67	40.64
	PEAT/OIL	213.28	73.852	50.8	82	41.656	171.624	65	264.037	442.531	706.568	65	16.69	40.64
	MSW/GAS	213.28	73.852	53.2	79	42.028	171.252	65	263.465	443.103	706.568	65	16.67	40.64
	MSW/OIL	213.28	73.852	50.8	82	41.656	171.624	65	264.037	442.531	706.568	65	16.69	40.64
150 MW$_t$	GAS/GAS	1777.6	861.368	410.8	84	345.072	1432.528	84	1705.390	3125.81	4831.2	84	27.56	54.62
	OIL/OIL	1777.6	861.368	394.4	88	347.072	1430.528	88	1625.600	2980.9	4606.5	88	28.90	57.29
	COAL/GAS	1777.6	834.170	410.8	84	345.072	1432.528	84	1705.390	3185.41	4890.8	84	26.19	53.40
	COAL/OIL	1777.6	834.170	394.4	88	347.072	1430.528	84	1703.010	3187.79	4890.8	84	26.17	53.40
	WOOD/GAS	1777.6	823.287	410.8	84	345.072	1432.528	79	1813.327	4012.273	5825.6	79	20.52	44.65
	WOOD/OIL	1777.6	823.287	394.4	88	347.072	1430.528	79	1810.795	4014.805	5825.6	79	20.51	44.65
	PEAT/GAS	1777.6	823.287	410.8	84	345.072	1432.528	75	1910.037	3915.563	5825.6	75	21.03	44.65
	PEAT/OIL	1777.6	823.287	394.4	88	347.072	1430.528	75	1907.371	3918.229	5825.6	75	21.01	44.65
	MSW/GAS	1777.6	823.287	410.8	84	345.072	1432.528	70	2046.469	3779.131	5825.6	70	21.79	44.65
	MSW/OIL	1777.6	823.287	394.4	88	347.072	1430.528	70	2043.611	3781.989	5825.6	70	21.77	44.65

Table 6-34 (Cont'd)

Breakdown of Cogeneration Station Performance

STATION SIZE	FUEL	ANNUAL HEAT PRODUCTION OF COGEN + PEAKING UNITS (TABLE 6-33)	ANNUAL POWER PRODUCTION (TABLE 6-33)	ANNUAL FUEL CONSUMPTION OF PEAKING BOILER (TABLE 6-33)	EFFICIENCY OF PEAKING BOILER (TABLE 6-32)	ANNUAL HEAT PRODUCTION OF PEAKING BOILER (4 X 5÷100)	ANNUAL HEAT PRODUCTION OF COGEN UNIT (2 - 6)	EFFICIENCY OF COGEN UNIT BOILER (TABLE 6-32)	ANNUAL FUEL CONSUMPTION OF COGEN UNIT			EFFICIENCY OF HEAT AND POWER PRODUCTION		
									FOR HEAT (7÷8 X 100)	FOR POWER (11 - 9)	FOR CHP (TABLE 6-33)	HEAT (8)	POWER (3÷10)	CHP (2+3÷11)
		GJ X 10^3	GJ X 10^3	GJ X 10^3	%	GJ X 10^3	GJ X 10^3	%	GJ X 10^3	GJ X 10^3	GJ X 10^3	%	%	%
0	1	2	3	4	5	6	7	8	9	10	11	12	13	14
300 MW_t	GAS/GAS	3553.56	2747.476	796	84	668.64	2884.92	84	3434.43	7330.05	10764.48	84	37.48	58.54
	OIL/OIL	3553.56	2747.476	765	88	673.20	2880.36	88	3273.14	7002.06	10275.20	88	39.24	61.32
	COAL/GAS	3553.56	2664.694	796	84	668.64	2884.92	84	3434.43	7330.05	10764.48	84	36.35	57.77
	COAL/OIL	3553.56	2664.694	765	88	673.20	2880.36	84	3429.67	7334.81	10764.48	84	36.33	57.77
	COAL/COAL	3553.56	2662.063	796	84	668.64	2884.92	84	3434.43	7330.05	10764.48	84	36.32	57.74
	WOOD/GAS	3553.56	2631.574	766	84	643.44	2910.12	79	3683.70	7762.10	11445.80	79	33.90	54.04
	WOOD/OIL	3553.56	2631.574	795	88	699.60	2853.96	79	3612.61	7833.19	11445.80	79	33.60	54.04
	WOOD/COAL	3553.56	2628.943	766	84	643.44	2910.12	79	3683.70	7762.10	11445.80	79	33.87	54.02
	PEAT/GAS	3553.56	2631.574	796	84	668.64	2884.92	75	3846.56	7599.24	11445.80	75	34.63	54.04
	PEAT/OIL	3553.56	2631.574	765	88	673.20	2880.36	75	3840.48	7605.32	11445.80	75	34.60	54.04
	PEAT/COAL	3553.56	2628.943	796	84	668.64	2884.92	75	3846.56	7599.24	11445.80	75	34.59	54.02
1500 MW_t	GAS/GAS	17774.4	18824.889	3982.4	84	3345.22	14429.18	84	17177.50	41236.40	58414.0	84	45.65	62.66
	OIL/OIL	17774.4	18824.889	3832.0	88	3372.16	14402.24	88	16366.18	39392.22	55758.4	88	47.79	65.64
	COAL/GAS	17774.4	18280.893	3982.4	84	3345.22	14429.18	84	17177.60	41236.40	58414.0	84	44.33	61.72
	COAL/OIL	17774.4	18280.893	3832.0	88	3372.16	14402.24	84	17145.52	41268.48	58414.0	84	44.30	61.72
	COAL/COAL	17774.4	18267.743	3982.4	84	3345.22	14429.18	84	17177.60	41236.40	58414.0	84	44.30	61.70

TABLE 6-35

Cogeneration Station - Summary of Annual Cost Data

STATION SIZE	FUEL COGENERATION/ PEAKING	TOTAL CAPITAL COST $\$ \times 10^6$	ANNUAL O & M COST $\$ \times 10^6$
18 MW_t	GAS/GAS	18.184	0.656
	OIL/OIL	19.3	0.664
	COAL/GAS	21.944	1.036
	COAL/OIL	22.264	1.044
	WOOD, BIOMASS/ GAS	22.524	1.136
	WOOD, BIOMASS/ OIL	22.844	1.144
	PEAT/GAS	24.444	1.136
	PEAT/OIL	24.764	1.144
	MSW/GAS	30.3	1.136
	MSW/OIL	30.62	1.144
150 MW_t	GAS/GAS	93.5	2.628
	OIL/OIL	99.08	2.652
	COAL/GAS	130.252	3.428
	COAL/OIL	131.512	3.452
	WOOD, BIOMASS/ GAS	163.14	3.828
	WOOD, BIOMASS/ OIL	164.4	3.852
	PEAT/GAS	186.14	3.828
	PEAT/OIL	187.4	3.852
	MSW/GAS	233.516	3.828
	MSW/OIL	234.776	3.852
300 MW_t	GAS/GAS	200.884	3.304
	OIL/OIL	212.56	3.348
	COAL/GAS	307.084	4.416
	COAL/OIL	309.16	4.464
	COAL/COAL	365.2	5.58
	WOOD, BIOMASS/ GAS	332.284	4.812
	WOOD, BIOMASS/ OIL	334.36	4.856
	WOOD, BIOMASS/ COAL	390.4	5.976
	PEAT/GAS	406.484	4.812
	PEAT/OIL	408.56	4.856
	PEAT/COAL	464.6	5.976
1500 MW_t	GAS/GAS	657.14	11.024
	OIL/OIL	719.9	11.14
	COAL/GAS	905.54	14.224
	COAL/OIL	913.1	14.34
	COAL/COAL	1038.2	16.216

NOTE: Total Stations consist of following:

Station Size	=	Cogeneration Sets	+	Peaking Boilers
18 MW_t		4 x 3 MW_t/78 MW_e (1 MW_e)		4 x 3 MW_t
150 MW_t		4 x 25 MW_t/8.5 MW_e (11.5 MW_e)		4 x 25 MW_t
300 MW_t		4 x 50 MW_t/28 MW_e (35 MW_e)		4 x 50 MW_t
1500 MW_t		4 x 250 MW_t/197 MW_e (230 MW_e)		4 x 250 MW_t

643 CAPITAL COSTS

The capital costs of the cogeneration stations are derived from in-house data on the cost of electrical generating stations and adjusted to include modifications for the district heating equipment. The estimates for the low pressure boilers of the heat only stations and the peaking boilers of the cogeneration station were based on steam generators investigated by Monenco in previous studies.

The capital costs include direct and indirect costs of the plants. Direct costs include site preparation, civil work, equipment supply and construction. For the coal-fired units, coal and ash handling equipment is included, although no allowance has been made for sulphur dioxide (SO_2) control such as flue gas treatment equipment. Contingencies for land values, extraordinary requirements for cooling water systems and unforeseen site difficulties such as seismic conditions, and their associated effects on foundations and structurals, are not included.

Indirect costs are very site specific, and can range from 30 to 70 percent of the direct capital costs. The percentage breakdown of indirect costs for the cogeneration sets is provided in Table 6-36. Indirect costs for the heat only stations and peaking boilers of the cogeneration stations are estimated at 50 percent of direct costs for all sizes.

Annual capital charges are based on an interest rate of 5%, amortized over the 30 year station life.

TABLE 6-36

Indirect Costs as a Percentage of Direct Costs

		10 MW	50 MW	100 MW	500 MW
ENGINEERING & CONSTRUCTION					
Includes:	Construction Facilities	2	1	1	1
	Testing & Commissioning	2	1	1	1
	Engineering & Proj. Mgt.	15	12	12	10
	Construction Mgt.	3	2	2	1.5
		22	16	16	13.5
OWNER'S COSTS					
Includes:	Taxes & Insurance	2	2	2	2
	Administration	1	1	0.5	0.5
	Training	1	1	1	1
	Spares	2	1	1	1
	Environmental Studies/ Licencing	1	1	1	1
	Provision of Working Capital	5	5	5	5
	Contingency	10	10	10	10
		22	21	20.5	20.5
INTEREST DURING CONSTRUCTION		5	5	5	5
	Total Percentage	49	42	40.5	39

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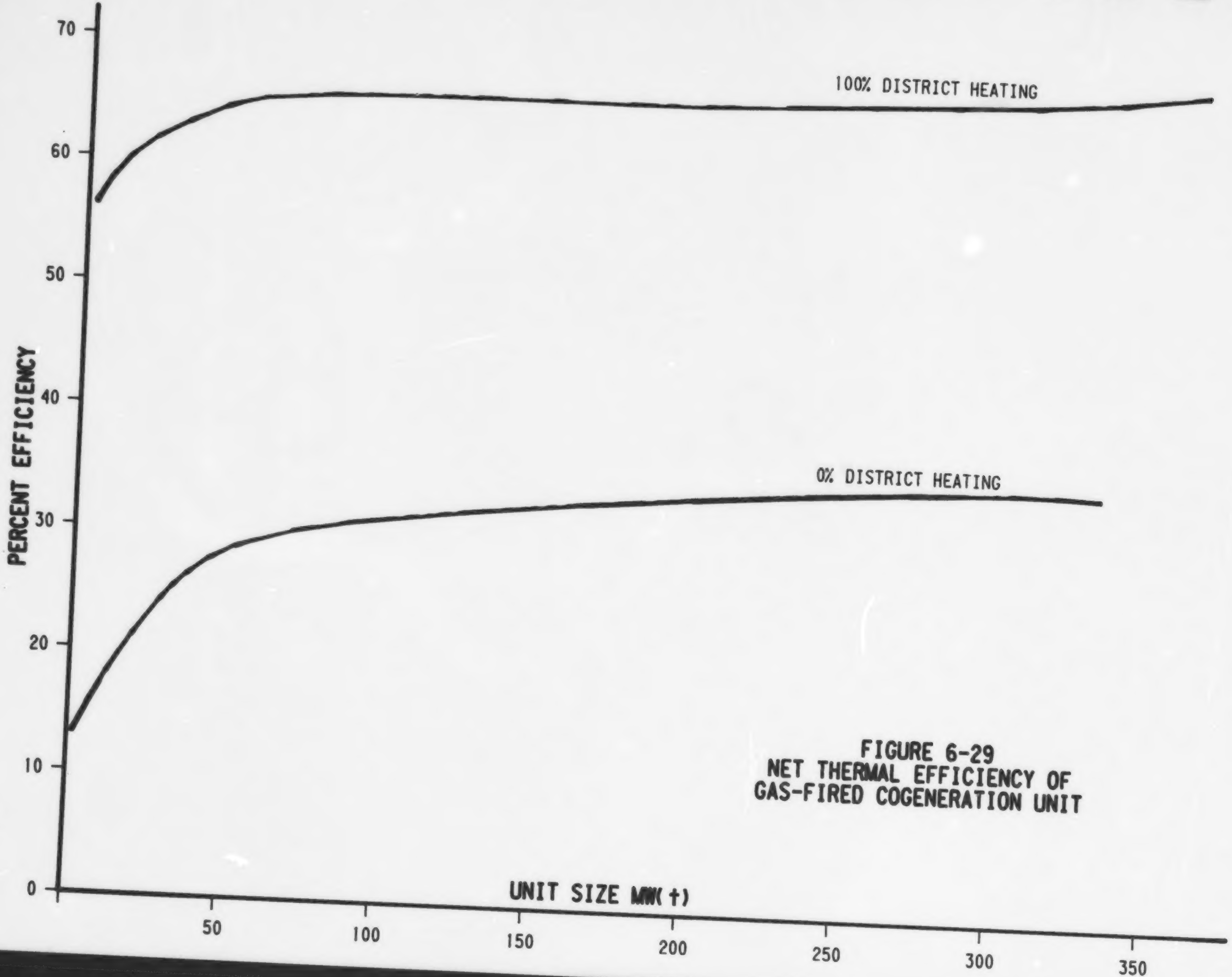

FIGURE 6-29
NET THERMAL EFFICIENCY OF
GAS-FIRED COGENERATION UNIT

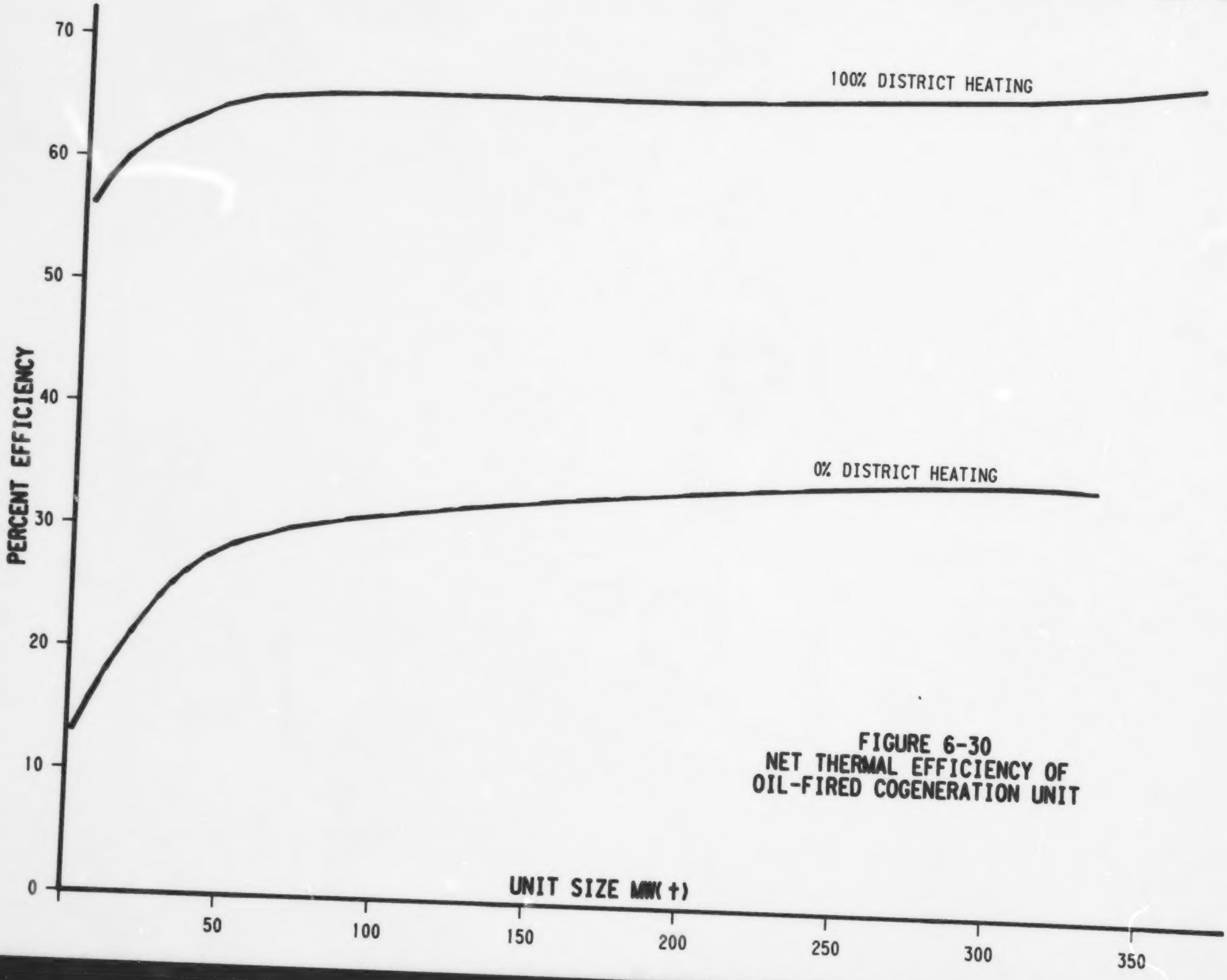

FIGURE 6-30
NET THERMAL EFFICIENCY OF
OIL-FIRED COGENERATION UNIT

[100,77]DSS631 .DGN

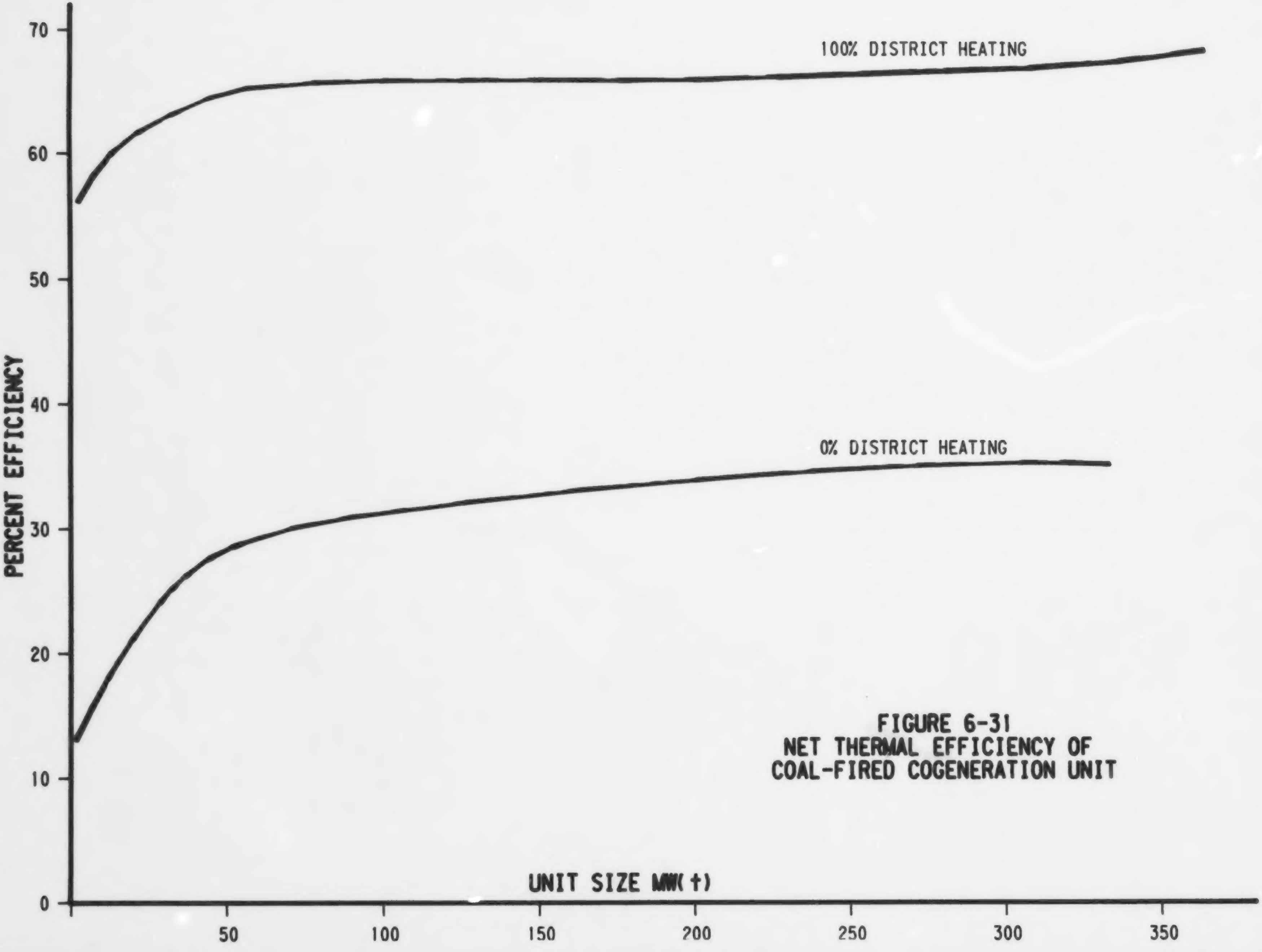

FIGURE 6-31
NET THERMAL EFFICIENCY OF
COAL-FIRED COGENERATION UNIT

[100,77]DSS632 .DGN

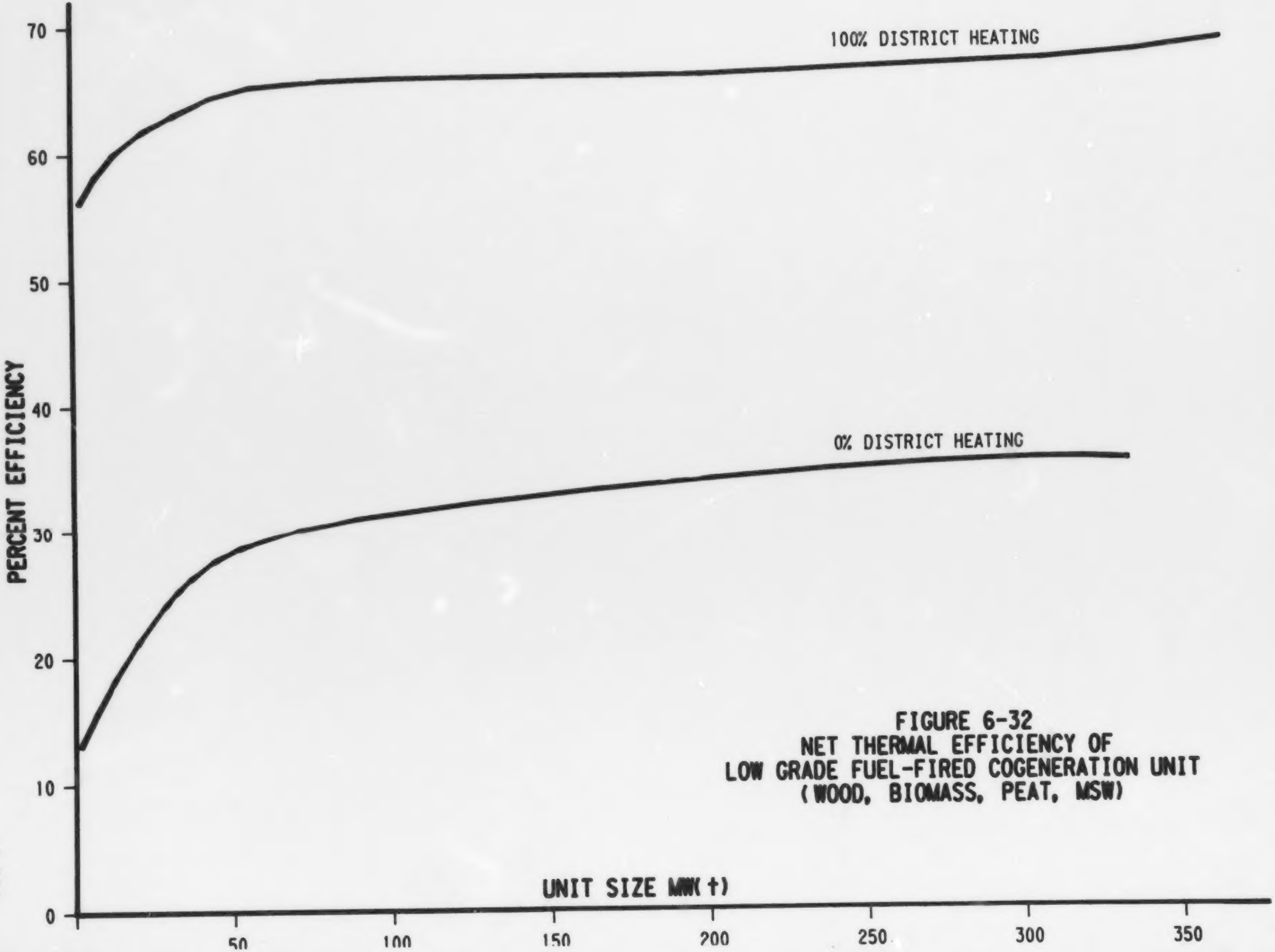

FIGURE 6-32
NET THERMAL EFFICIENCY OF
LOW GRADE FUEL-FIRED COGENERATION UNIT
(WOOD, BIOMASS, PEAT, MSW)

644 OPERATING AND MAINTENANCE COSTS

The annual operating and maintenance costs are assumed to be 2% of capital for the 18 and 150 MW_t heat only stations and 1.5% for the 300 and 1500 MW_t stations.

The annual operating and maintenance costs of the cogeneration sets are based on each of the four units operating 6570 hours per year at maximum continuous rating. Three of the four units are assumed to be in operation with the fourth unit serving as standby.

Operating and maintenance costs are based on in-house data for electric generating stations.

The annual operating and maintenance costs for the peaking units are based on each of the four units operating 1725 hours per year to suit peak heating demand. Operating and maintenance costs are assumed to be 2% of capital for the 3 and 25 MW_t units and 1.5% for the 50 and 250 MW_t units.

645 FUEL COSTS

The cost of fuel is very dependent upon the transportation distance to the site. The fuel prices used in the study are set out in Table 6-7.

Volume

2

THE REALISTIC POTENTIAL
FOR DISTRICT HEATING IN CANADA
VOLUME II

(Volume 2 of 2)

Prepared by

Monenco Consultants Limited

in association with

DHM Energy Consultants Ltd.
K-Konsult
Cogeneration Associates Limited

April, 1985

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7.1 GENERAL

The transmission and distribution network of a DH system consists of an insulated pipe system, designed and constructed to transport the heating fluid from the heating plant to the subscriber. These complex and capital intensive piping systems are usually installed below grade, either by direct burial or in tunnels. The systems must withstand forces created by thermal expansion, internal pressures, external forces and ground water problems. In order to assess the different options available for these systems their various features are described and analyzed under the following headings:

- design criteria;
- the transmission system;
- the distribution network; and
- capital costs.

7.2 DESIGN CRITERIA

721 GENERAL

The transmission and distribution piping network of a DH system is a complex engineering system with numerous interdependent design parameters. The heat delivered is a function of water velocity, temperature drop and pipe system heat loss and these, in turn, are dependent upon the physical characteristics of the system.

The following parameters must be considered in the design of any district heating project:

- heat transfer fluid;
- temperature program including maximum supply temperature and temperature drop;
- maximum and minimum system pressure for the distribution network;
- pressure drop through the subscriber installation;
- water velocity;
- diversity factor; and
- insulation and heat losses.

The main features of these parameters affecting the design and performance of a DH system are discussed in the following pages.

.1 Heat Transfer Fluid

There are essentially three fluid types that can be used to transport heat. They are organic, steam and water. Steam is usually distributed at low pressure (0-103 kPa), medium pressure (103-1034 kPa) and high pressure (above 1034 kPa). A small number of vacuum systems are used to heat buildings but they are not installed in new buildings in Canada and the USA.

ASHRAE classifies hot water heating systems by both pressure and temperature. They classify low temperature below 1100 kPa and 121°C; medium temperature between 1100 and 2060 kPa and 121 to 176°C; and high temperature water above 2060 kPa and 176°C. For the purposes of this study, hot water is classified as low temperature (90°C), medium temperature (120°C), and high temperature (200°C max.)

.11 Organic Fluid Organic fluids possess the desirable physical properties of having a high boiling point and a low freezing point. They are not however commonly used as a heat transfer fluid except for special cases because the fluid typically, is expensive and toxic.

.12 Steam and High Temperature Water In steam based DH systems steam is produced in steam generators or extracted from steam turbines and is distributed directly to the transmission system. A complete transmission and distribution network consists of steam and condensate return lines which are usually installed in metal or concrete conduits, culvert or tunnels. In many existing steam systems the condensate pipe was never installed or is no longer in service due to pipe failure. A common practice in many older steam systems was to drain the condensate to the sewer system at whatever temperature it was discharged from the subscriber equipment.

Pipes made of corrosion resistant reinforced fibreglass material have been developed and are available in Canada. These pipes have been used for some condensate return systems but the design must ensure that high pressure steam cannot enter the condensate system because the maximum working temperature of the pipe is 95°C. Furthermore, past experience has shown that the installed costs are high for such pipe systems.

There are several benefits to using steam in DH systems. It has a very high latent heat of evaporation and it can be transported at a very high velocity. As a result of these characteristics, a given quantity of heat can be transported by steam for distances of 2 to 3 km in smaller pipes than if the fluid were water. If however, the length of the transmission and distribution network exceeds this distance, the pipe diameter for a hot water system will be smaller. Therefore, if the transmission and distribution network is extensive, hot water is more easily transported than steam because it can be pumped while steam can only be transported by pressure head.

Increasing pressure head as a means of increasing the length or size of a steam based transmission and distribution network, will however impose a large construction cost penalty since the class of the pipe and fittings and the cost of construction are significantly increased if the design pressure exceeds 1034 kPa.

A survey of steam DH systems in Canada indicates that they operate with overall thermal efficiencies of between 45 and 70 percent. This is clearly unattractive and not competitive with individual heating systems. Furthermore, there is little that can be done to increase the efficiency beyond measures such as heating the make-up water and combustion air with heat recovered from the flue gases. If there are no condensate return lines or if the steam and condensate lines have insufficient insulation, it is usually not economically feasible to retrofit these systems, even if the lines are in tunnels rather than direct buried.

For most DH systems, the use of steam in the production plant does not necessarily impose a problem or a penalty and only a minor penalty on the subscriber system. The use of steam in the transmission and distribution network does, however, impose a prohibitive capital and operating cost penalty on most DH systems.

For the case of HTHW systems, construction and operating regulations in Canada and the USA are similar to those required for steam systems due to the high temperature and pressure. Consequently, the cost of the HTHW pipe system is considerably more expensive than other hot water systems. In addition, the temperature of a HTHW system is much higher than is acceptable for factory applied polyurethane pipe insulation and consequently, the insulation process is usually more expensive. In the case of the HTHW system recently installed in Trenton, New Jersey, this problem was overcome by factory installation of a layer of foam glass insulation around the pipe followed by a second layer of polyurethane insulation.

Although HTHW systems generally operate at a higher efficiency than steam, none of the Canadian systems reviewed in the study had an overall operating efficiency exceeding 70 percent. In general, HTHW systems are limited to low operating efficiencies for many of the same reasons that affect steam systems. For example, they have high thermal losses in the transmission and distribution network.

Steam will, of course, continue to be used as the heating fluid in cogeneration production plants and for other systems involving industrial processes. However, in view of the generally poor performance of steam and HTHW systems in Canada and the USA and the limitations and penalties such fluids impose on DH systems, they have been excluded in the determination of system costs for use in this study.

.13 Low Temperature Water This type of heat source differs from LTHW because the water is usually below the minimum temperature (60°C) that can be used in building heating systems. Therefore, it is necessary to install a heat pump in the buildings to increase the water temperature to a suitable level for heating purposes. An example where such a system could be used is the extraction of heat from the domestic water supply. This approach was examined in a study involving the extraction of heat from the domestic water system for Townsend, Ontario. The water would have been drawn from Lake Erie after it had been heated by the condenser water from the Nanticoke Thermal Generating Station. As discussed in Part 6.2 however, commercial installations of such systems are a relatively recent development and not fully proven. Consequently, they are not analysed in this report.

.14 Medium and Low Temperature Hot Water MTHW and LTHW systems designed with a high temperature drop, have been built and operated in Europe for more than 30 years. Most systems being built or under study in Canada and the USA will use water at these temperatures because they combine a number of attractive characteristics not offered by other heat transfer fluids including:

- high heat transport capacity;
- moderate thermal expansion requirements;
- modest loss in electrical production if heat produced by cogeneration;
- permits sliding-temperature operation to reduce heat losses and reduction of cogenerated electricity;
- permits direct connection to any type of heating in houses without life safety concern, provided the maximum temperature is less than 100°C;
- provides a heat sink for low grade heat recovery in conjuction with heat pumps; and
- permits the use of polyurethane insulation which facilitates high performance, moderate cost factory insulated pipe systems.

There is little doubt of the success of LTHW and MTHW systems installed in Europe. The recent installations of such transmission and distribution networks in LeBreton Flats, Ottawa and St. Paul have also experienced satisfactory operation. The prevailing view among engineers involved with district heating in Canada and the USA, favours LTHW and MTHW systems when considering new district heating systems. Consequently, the analyses in this study are based on MTHW and LTHW fluids.

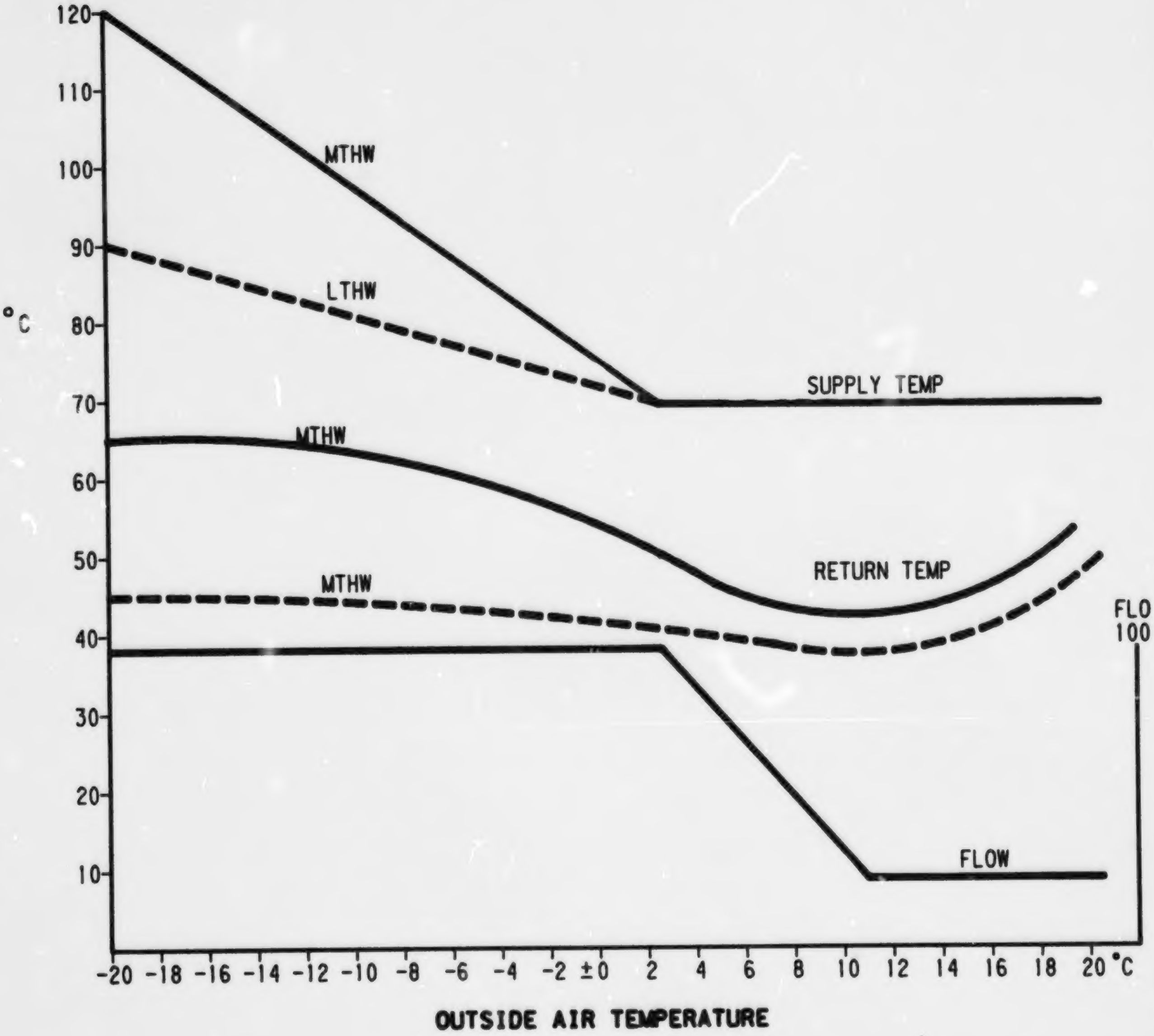
.2 Temperature Program

The temperature program describes the variation of the supply and return temperatures of the heat transfer fluid during the year. A typical temperature return program is given in Figure 7-1. The supply temperature and, in some cases, the flow rate is varied by a system control located in the heat plant in accordance with the outdoor temperature. The heat transfer fluid is heated to the maximum design temperature when the outdoor temperature is at a minimum and the return temperature is determined by the temperature drop in the subscriber systems. The design of the subscriber installation is described in more detail in Part 8. The difference between the maximum supply and the minimum return temperature is the maximum temperature drop. This is one of the most important parameters in the design of the distribution network. The magnitude of the temperature drop, which is largely a function of the design and operation of the subscriber system, affects key design factors such as pipe diameter, pumping costs, and pressure loss.

The determination of the temperature program is complex and several factors must be considered. The following discussion deals with the most important factors and is based on two temperature alternatives: medium temperature and low temperature hot water systems. The medium temperature system is represented by a temperature program with a design supply temperature of 120°C, a return temperature of 65°C and a temperature difference is 55°C. The low temperature system operates with a supply temperature of 90°C and a temperature drop of 45°C to provide a return temperature of 45°C.

The most important factors when selecting the temperature program are:

- capital cost for the transmission and distribution network and subscriber system;
- pumping costs;



[100,77]DSS71 .DGN

FIGURE 7-1
TYPICAL RELATIONS BETWEEN THE OUTSIDE AIR TEMPERATURE AND SUPPLY AND RETURN WATER TEMPERATURE AND FLOW

- heat losses; and
- heat production systems i.e. boilers, cogeneration, heat pumps, etc.

The pipe diameter of the distribution network is affected by the difference in temperature drop for the medium and low temperature systems. Because the low temperature system has a smaller temperature drop, the reduction in heat delivered per unit mass of water must be compensated for by an increase of approximately 20 percent in the water flow. Assuming a constant water velocity, this will require an increase in pipe diameter. Pipe diameters which have been designed based on a temperature drop of 55°C, and with little or no spare capacity must be increased one standard pipe size, when the temperature drop is reduced to 45°C. The additional cost for the increase in pipe size is approximately 5 to 10 percent. The predesign calculations carried out for three sites which are described in Section 7.5 for three sites illustrate the differences in pipe sizes required by medium and low temperature systems.

The low temperature system requires a larger flow, and therefore more energy is required by the circulation pumps. The cost difference for this heat is equal to the cost of the energy used to drive the motor less the cost to produce this heat by the heating plant. For most systems, this would not be a significant cost factor.

The heat losses depend primarily on the temperature difference between the surrounding ground and the fluid. This difference is less, and consequently, the heat loss of the lower temperature system is of the order of 10 percent less than the medium temperature system notwithstanding the fact that the pipe sizes, and therefore the surfaces of the pipes, are larger. This difference in heat losses typically represents approximately half of one percent of the fuel consumption for the system.

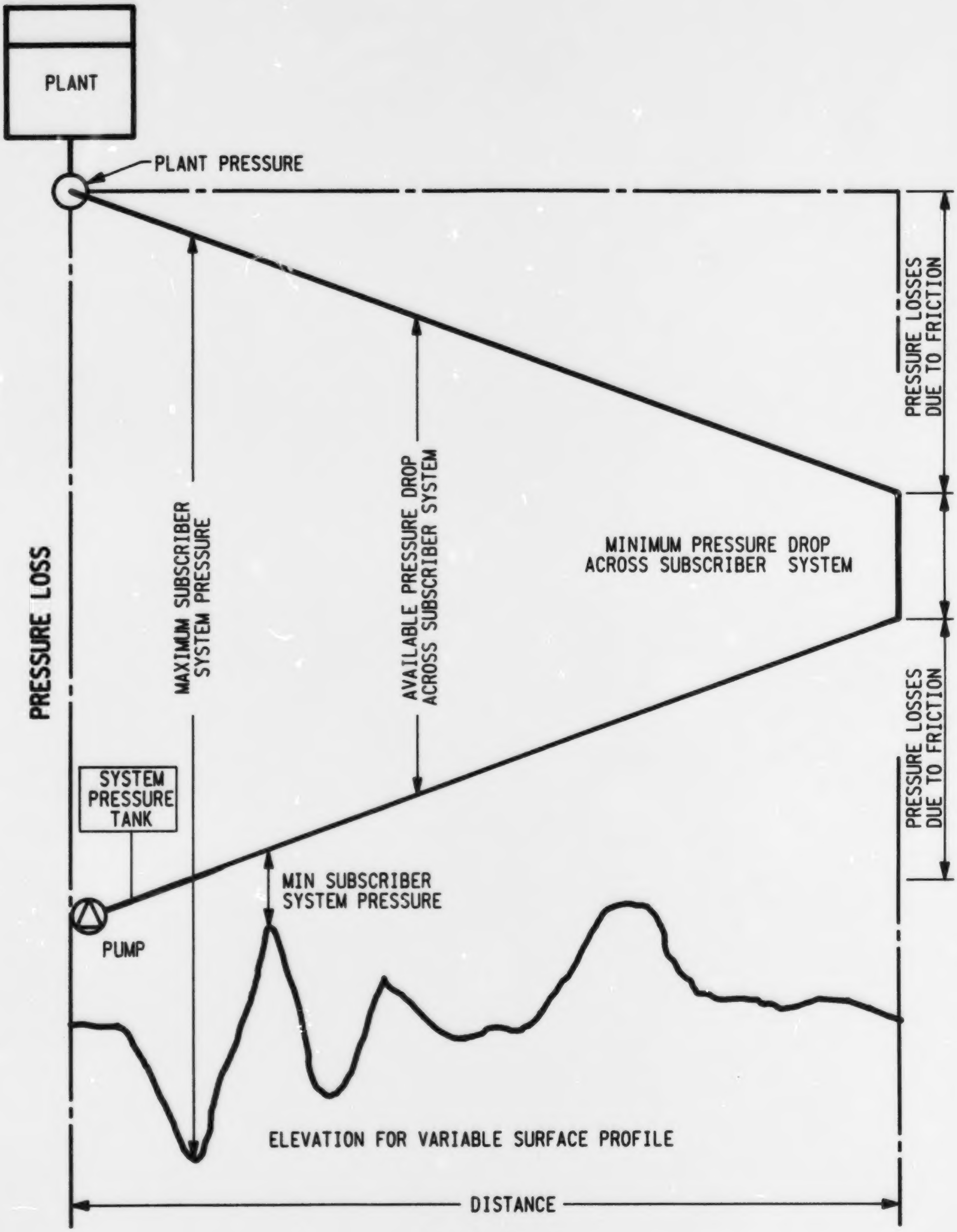
The higher capital cost of lower temperature systems could be offset by the increased potential of using cogeneration, or even lower temperature heat sources, such as direct heat transfers from industrial processes, or from heat pumps, which use a variety of low grade heat sources.

.3 Maximum and Minimum System Pressure

Water pressure in the transmission and distribution networks must be considered in the design and operation of a DH system. A number of techniques such as the use of primary and secondary pumping, booster pumps and the location of building heat exchangers can be used to control system pressure. A typical pressure diagram for a district heating system is shown in Figure 7-2.

Water leaves the plant at a high pressure to overcome the pressure losses due to friction of the external systems, consisting of the transmission system, distribution network, and subscriber systems. The supply and return pipes are usually of equal size, hence the pressure losses for these pipes should be equal. The extent of the pressure loss in the subscriber equipment depends upon the design of the heat exchanger and control system.

The pump is usually located in the return line in the heating plant in order to avoid the higher temperature water. It will increase the pressure as required to overcome the pressure losses in the plant and the external systems. It is common practice to regulate the basic static pressure (i.e. no flow condition) in the system with a pressure tank in the heating plant. This pressure should be regulated to maintain the lowest acceptable system pressure however it must always be higher than the steam saturation pressure in order to prevent boiling. Operating at low pressures permits the use of thin wall pipes and fittings, reduces the risk of joint rupture and minimizes the risk of leaks at equipment seals. The effect of elevation


PLANT
PLANT PRESSURE
PRESSURE LOSSES DUE TO FRICTION
MAXIMUM SUBSCRIBER SYSTEM PRESSURE
AVAILABLE PRESSURE DROP ACROSS SUBSCRIBER SYSTEM
MINIMUM PRESSURE DROP ACROSS SUBSCRIBER SYSTEM
PRESSURE LOSS
PRESSURE LOSSES DUE TO FRICTION
SYSTEM PRESSURE TANK
MIN SUBSCRIBER SYSTEM PRESSURE
PUMP
ELEVATION FOR VARIABLE SURFACE PROFILE
DISTANCE

[100,77]DSS72 .DGN

FIGURE 7-2
STATIC PRESSURE vs DISTANCE
TRANSMISSION & DISTRIBUTION NETWORK

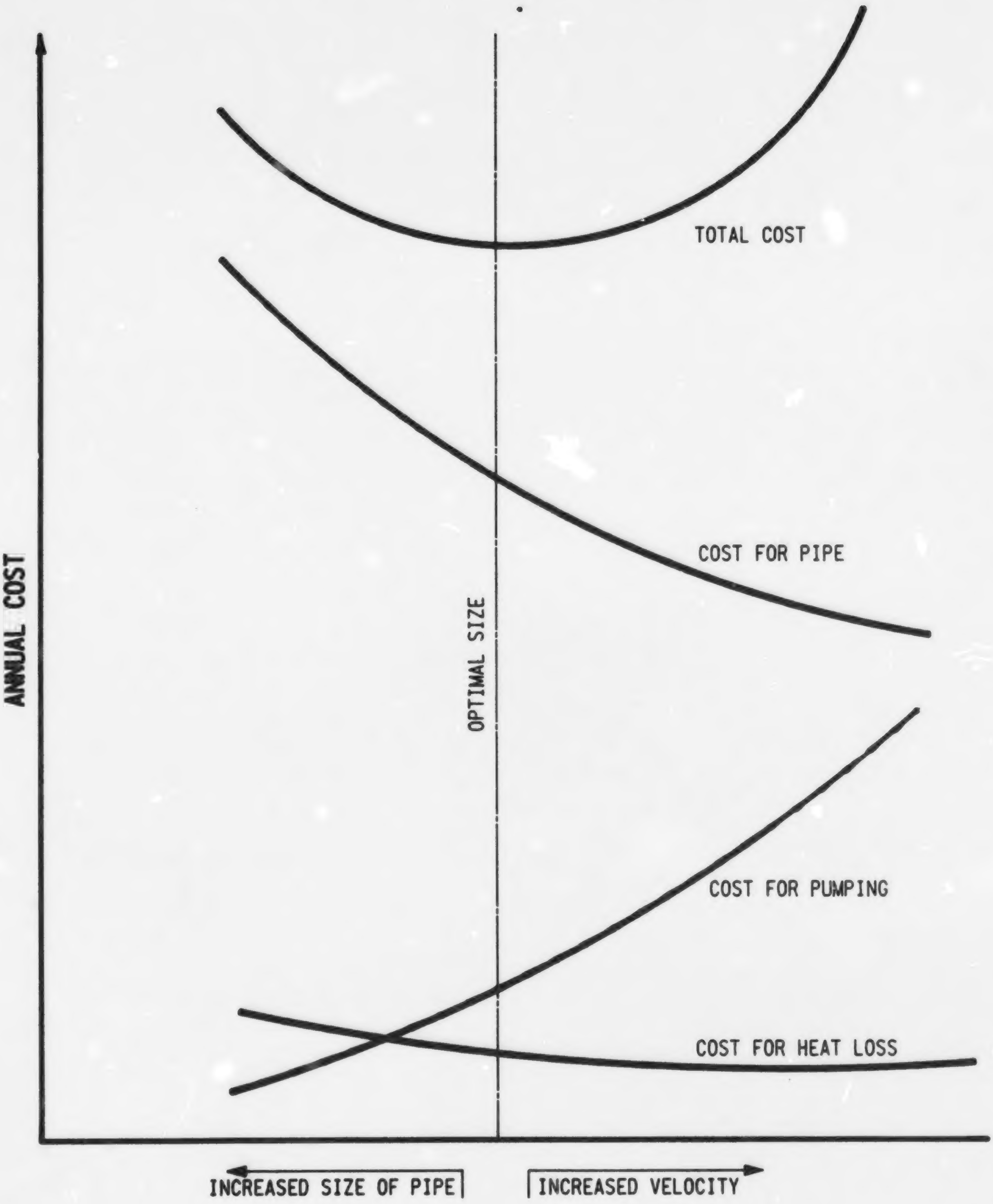
on various parts of the network is shown in Figure 7-2. The supply line will impose the highest pressure on subscriber systems which are located at a low elevation while the return lines of a subscriber system at a high elevation is adversely subjected to a low pressure in the return line. The design and operation of the DH system must therefore accommodate these pressure variations.

.4 Pressure Drop through the Subscriber Installation

The water flow through heat exchangers at the subscriber installation is regulated by control valves according to the actual demand. In order to ensure proper system operation there must be a significant pressure drop across the control valve even when it is fully open. On the other hand, it is desirable to have a low pressure drop across the subscriber equipment. This low pressure drop will increase the size and cost of the equipment. Therefore, when designing the subscriber systems, it is necessary to consider the effect of the pressure drop on the various components. These items are discussed more extensively in Part Eight.

.5 Water Velocity

The determination of pipe sizes is dependent primarily on the temperature drop between the supply and return fluid and on the quantity of heat to be transported through the pipes. An optimization of pipe sizes should take into account the costs for different pipe sizes, pumping losses and heat losses. Increased water velocity allows the pipe diameters to be smaller, thus reducing the cost of the pipes as well as decreasing the heat losses. The cost for pumping however increases due to increased friction losses. The relationship of the cost factors normally included in design optimization are shown in Figure 7-3.



[100,77]DSS73 .DGN

FIGURE 7-3
OPTIMIZATION OF PIPE SIZE

Proper optimization must recognize the variation of the flow during the year due to seasonal temperature changes and also the flow variation for different years. This could occur in parts of a network if district heating expands over a number of years. Normal design criteria is usually based on maximum design velocities for each diameter of pipe used, however pressure losses must also be analyzed carefully when designing the piping system. This is particularly important in the selection of smaller pipe diameters.

.6 Diversity Factor

Individual subscribers demand heat at different times during the day and consequently the maximum coincident demand on the system is less than the sum of the maximum individual subscriber heat demands. The ratio of the maximum coincident system load to the sum of the maximum individual subscriber loads is known as the diversity factor. A diversity factor of 80 percent indicates that the maximum coincident system load is 80 percent of the sum of the maximum individual subscriber loads. The importance of this factor is that the heating plant, the transmission system and to a large extent, the distribution network need only be designed to meet the maximum coincident system load.

Diversity factors are difficult to determine. However, it is known that the potential for diversity varies in proportion to the heat density. Therefore, for most systems, the load diversity will tend to decrease as one moves from the heat supply end to the extremities of the distribution network. In general, diversity factors are determined by experience and they differ for systems in different countries and for different parts of countries. In Sweden, where they have considerable experience with DH systems a diversity factor of 80 percent is often used.

.7 Heat Losses from Transmission and Distribution Network

The heat losses from a DH transmission and distribution network are related to the pipe surface area, the thermal resistance of the insulation and the temperature difference between the fluid and the ground. The heat loss is usually given as a percentage of the heat transferred through the network. The magnitude of this relative heat loss varies widely. In high density areas, the heat loss can be as low as 2 percent of heat input to the system while it can be as high as 20 percent or more in low density areas.

If the water velocity is the same in two similar networks, the network with the higher heat demand will have larger diameter pipes but lower relative heat losses. This is because heat losses are related to the pipe diameter while the heat demand is a function of the fluid flow and, hence, diameter squared. In practice, however, an increase in pipe diameter will allow an increase in the design velocity of the pipe fluid. Therefore, the flow and demand is increased by more than just the ratio of the square of the pipe diameters. In addition, the actual heat losses from an insulated pipe do not increase in direct proportion to the increase in pipe diameters. This will have a significant effect on the relative heat losses. For example, a 200 mm pipe has the capacity to carry approximately five times the flow of a 100 mm pipe while the heat losses are only about 50 per cent more than for the smaller one. These are the main reasons why relative heat losses increase when heat density and connected load, decrease. Furthermore, the distribution system is normally longer in a low density area due to the increased number of connections (increased connection density) and the larger area covered for the equivalent heat delivery. The additional piping for services also increases the relative surface area and heat losses. The relationship between heat density and relative heat losses is shown in Figure 7-4.

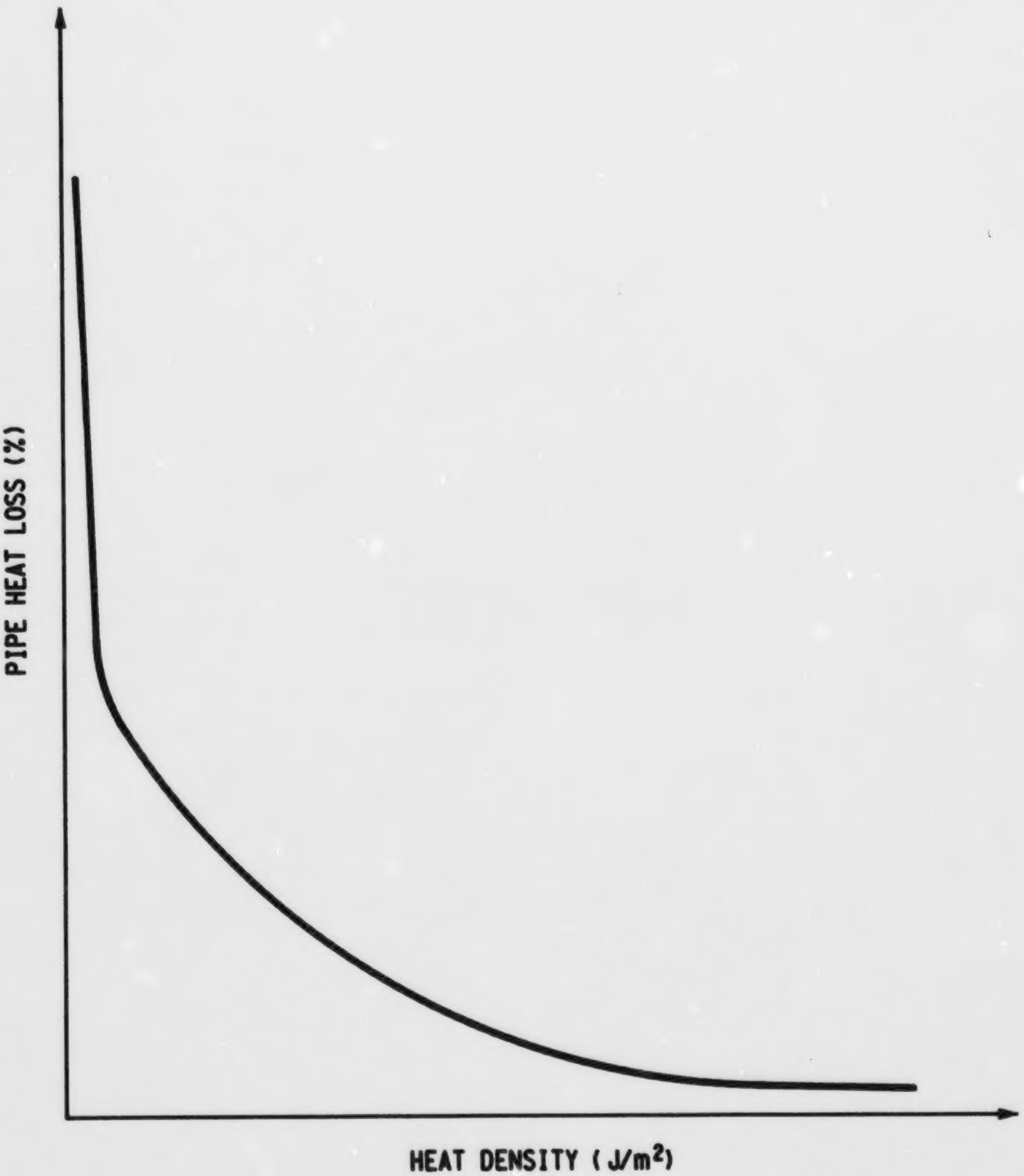


FIGURE 7-4
HEAT LOSS IN RELATION TO HEAT DENSITY

For a given pipe area and water temperature, the thermal resistance of the insulation and ground determine the heat losses per unit area of pipe. A large portion of the total thermal resistance is related to the insulation, however, ground conditions (and to a small degree burial depth) also affect the heat losses. The existence of ground water reduces the thermal resistance of the ground and, if it penetrates the protective jacket, the thermal resistance of porous insulating material could be significantly reduced. The use of polyurethane insulation decreases the effect of water penetration since it is a closed cell material and virtually impervious to water.

As noted earlier heat losses are proportional to the temperature difference between the heat transfer fluid and the ground. Therefore heat losses, for a given system, will decrease if the temperatures of the supply and return fluid are reduced.

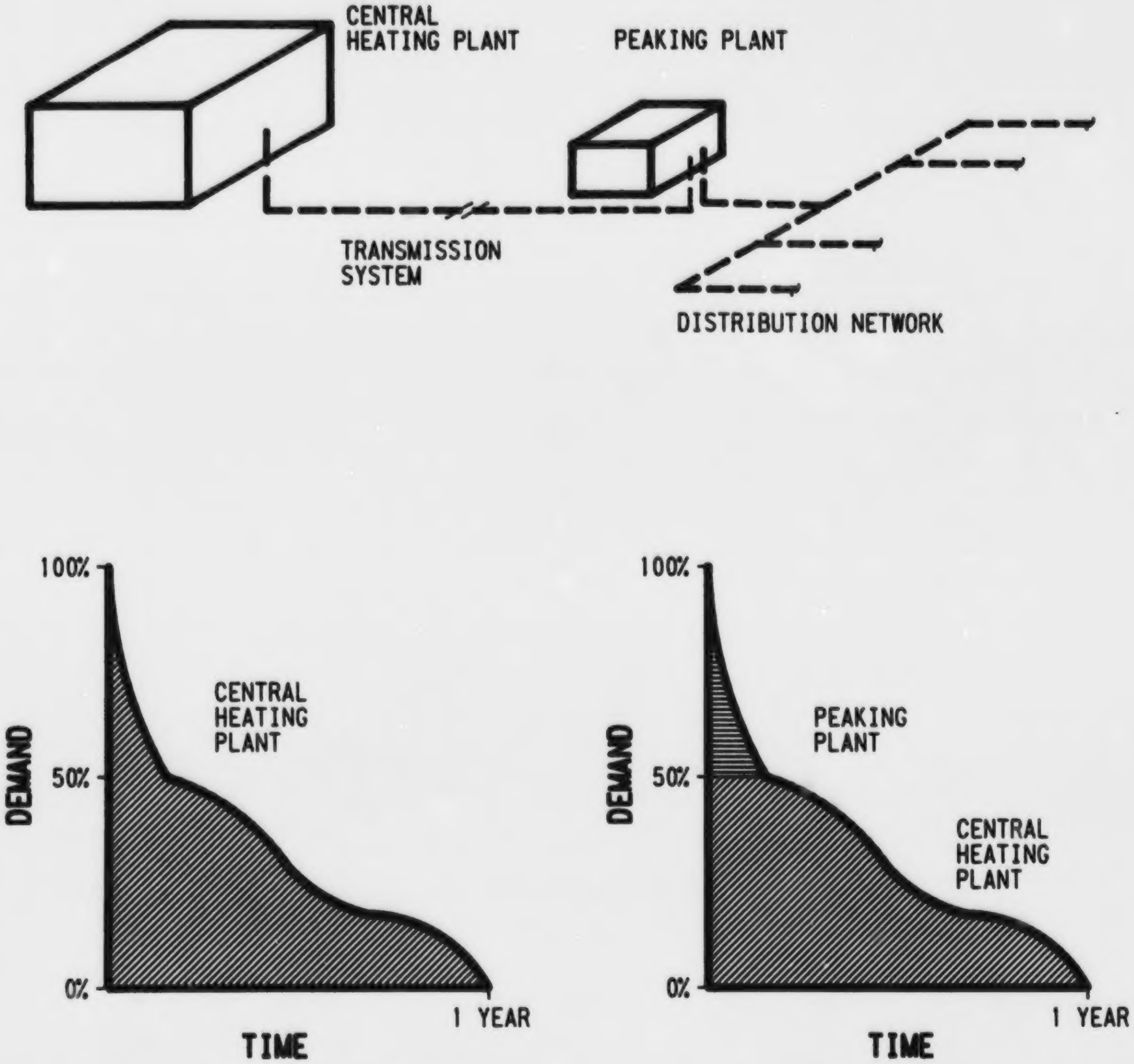
Pipe insulation not only has a direct bearing on fuel consumption, it also affects the size and capacity of all system equipment.

7.3 THE TRANSMISSION SYSTEM

It is desirable to build heat plants for DH systems close to major heat loads in order to minimize the capital costs and heat losses associated with a long transmission system. This was the common practice with early steam DH systems since it was technically difficult and expensive to transport steam over even relatively short distances and there were few environmental or other regulations that would prohibit the installation of the heat plant close to the heat center.

While many plants in Europe are located near the center of greatest heat load, studies have been performed to determine the feasibility of transmitting heat over extended distances particularly in circumstances where waste heat was available at little or no cost but at a considerable distance from the heat load. There are some installations in the USSR that have long transmission lines. One was also planned in Sweden to transport MTHW some 120 km from a nuclear plant to Stockholm. This system was not constructed however because the future of nuclear plants in Sweden is uncertain. A recent Canadian study recommends transporting hot water to Edmonton from a coal-fired electric generating plant under construction 64 km south of Edmonton [228]. The plan appears financially attractive based on the low cost attributed to heat cogenerated from steam turbines. A relatively low cost transmission line can be built to deliver heat to Edmonton using European type factory insulated pipe systems.

A transmission system can transport the total heat requirements to a district heating network; but, depending on the shape of the load duration curve the capital costs may be significantly reduced if the transmission system is sized to meet only the base load heating requirements. In this case, peaking boiler plants located adjacent to the distribution network would serve the peak heat load of the systems. The effect of this option is illustrated in Figure 7-5.


CENTRAL
HEATING PLANT
PEAKING PLANT
TRANSMISSION
SYSTEM
DISTRIBUTION NETWORK
100%
50%
0%
DEMAND
CENTRAL
HEATING
PLANT
1 YEAR
TIME
100%
50%
0%
DEMAND
PEAKING
PLANT
CENTRAL
HEATING
PLANT
1 YEAR
TIME

SYSTEM WITH PEAKING BOILERS INCLUDED IN CENTRAL HEATING PLANT

TRANSMISSION SYSTEM LOAD DURATION CURVE

SYSTEM WITH SEPARATE PEAKING PLANT

TRANSMISSION SYSTEM LOAD DURATION CURVE

FIGURE 7-5
TYPICAL LOAD DURATION CURVES FOR TRANSMISSION SYSTEMS

[100,77]DSS75 .DGN

7.4 THE DISTRIBUTION NETWORK

741 NETWORK LAYOUT

The distribution network connects the subscribers to the transmission system and/or the DH production plant. The network can be laid out in several ways and extensive calculations must be done to determine the costs and benefits of the alternatives. One basic design principle, however, that will reduce construction costs is to run the distribution mains through areas with the highest heat density and extend them to areas of progressively lower heat density. A second basic design principle is to design the layout with as many links or loops between various branches as possible. This will improve system reliability since it allows sections of the system to be isolated for repair and maintenance with minimal interruption of service. Such loops do however increase the cost to construct the network. An optimum network layout is shown in Figure 7-6.

The principal factors governing the layout of the network are the location and heat load of the subscribers, subsurface conditions, vehicular traffic patterns and the existence of other subsurface installations. The existence of rock increases the costs for the network substantially. If possible, streets with rock close to the surface should be avoided completely or, at least, not used for the larger mains.

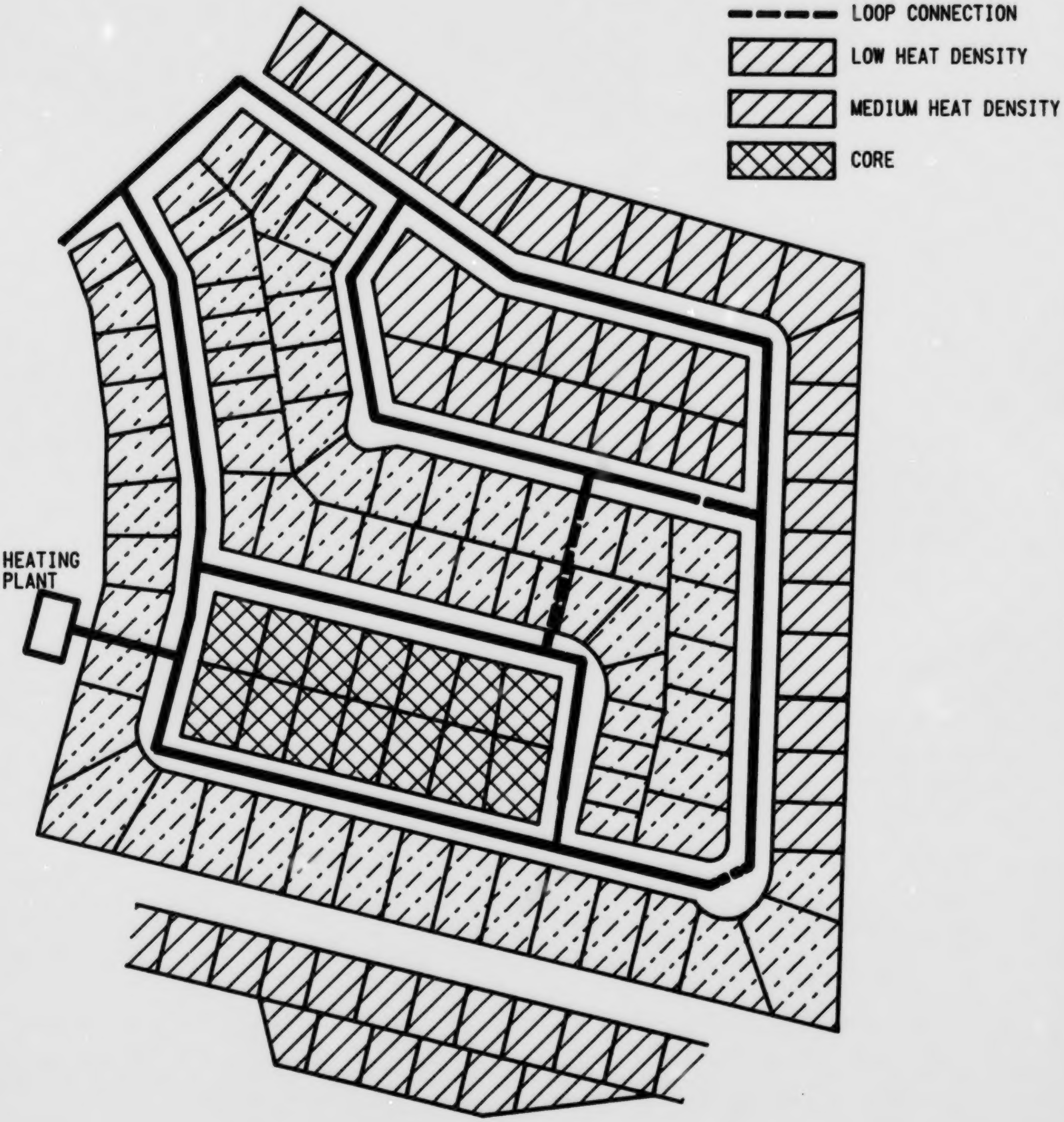

LOOP CONNECTION
LOW HEAT DENSITY
MEDIUM HEAT DENSITY
CORE
HEATING PLANT

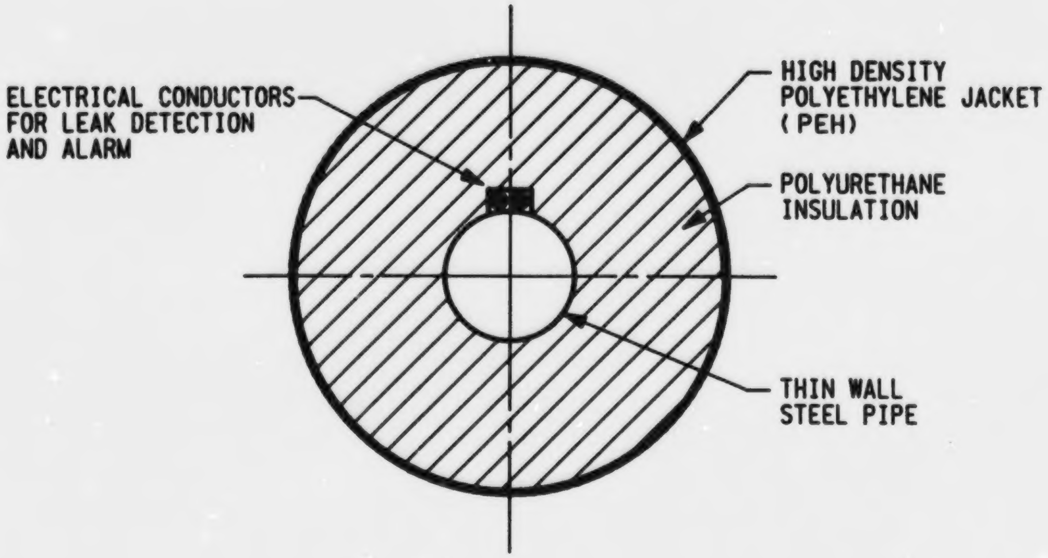
FIGURE 7-6
PREFERRED LAYOUT FOR DISTRICT HEATING NETWORK FOR A COMMUNITY OF MIXED USE AND OCCUPANCY

The factory insulated (European) pipe system has been used extensively for LTHW and MTHW installations. It consists of a thin wall steel pipe and a heavy duty polyethylene jacket. Polyurethane is expanded into the annular space between the two pipes. Construction and installation details of the pipe, which is suitable for direct burial, are shown on Figures 7-7 to 7-11 inclusive.

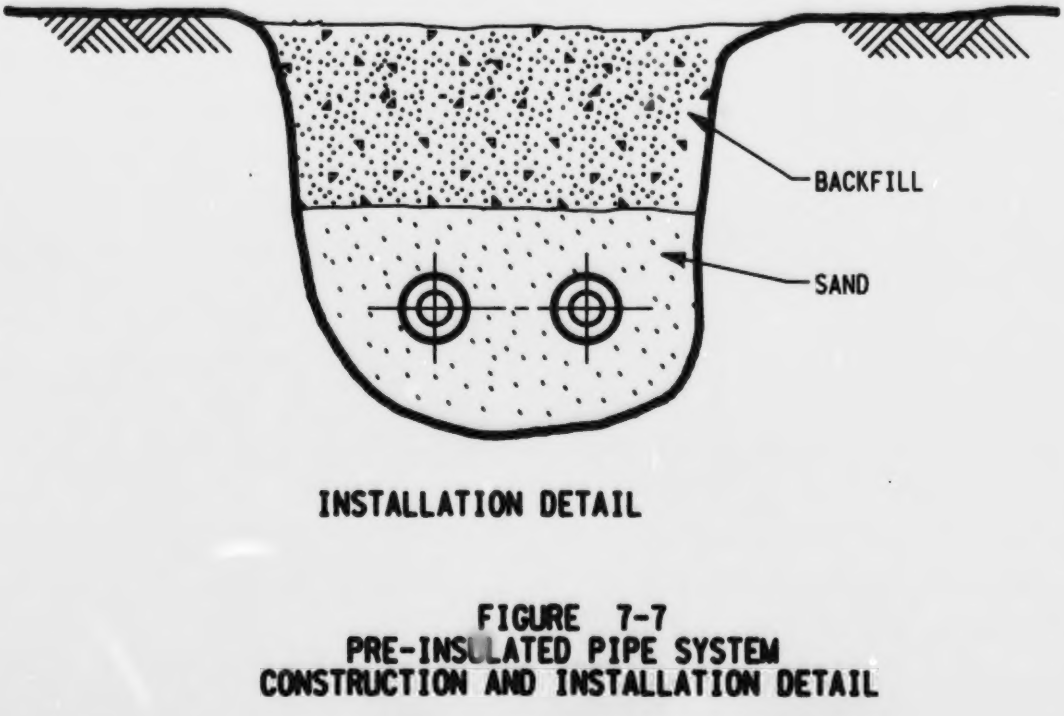
Pipe sections are manufactured in 12 m lengths complete with a wide assortment of fittings, making field installation relatively simple and inexpensive. Techniques have been developed to provide joints consisting of polyurethane insulation covered by a polyethylene joining sleeve making the complete system waterproof.

Burial depth is determined by the expected loads on the surface and the allowed pressure on the pipes. If shallow buried pipes cross areas of heavy traffic, they must be covered with concrete or enclosed in a concrete culvert as shown in Figure 7-8. In general, it is desirable and less expensive to install all of the distribution lines as shallow as possible and if they are installed either under the sidewalks or under grassed areas between sidewalks and buildings they are reasonably accessible for repair and maintenance work.

Take-off fittings are expensive in the main distribution line and consequently, a number of alternatives should be considered to ensure take-offs are only made when it is possible to supply a significant quantity of heat to an area as shown on Figure 7-12. This is not a problem in high density areas, but in low density areas this can be achieved by arranging for one take-off to feed a number of houses from a sub-branch system. Sub-branches can be made of small diameter pre-insulated steel lines or they can be constructed from copper pipe systems that have been found to be quite economical and successful in Sweden. The copper systems generally require much less


ELECTRICAL CONDUCTORS FOR LEAK DETECTION AND ALARM
HIGH DENSITY POLYETHYLENE JACKET (PEH)
POLYURETHANE INSULATION
THIN WALL STEEL PIPE

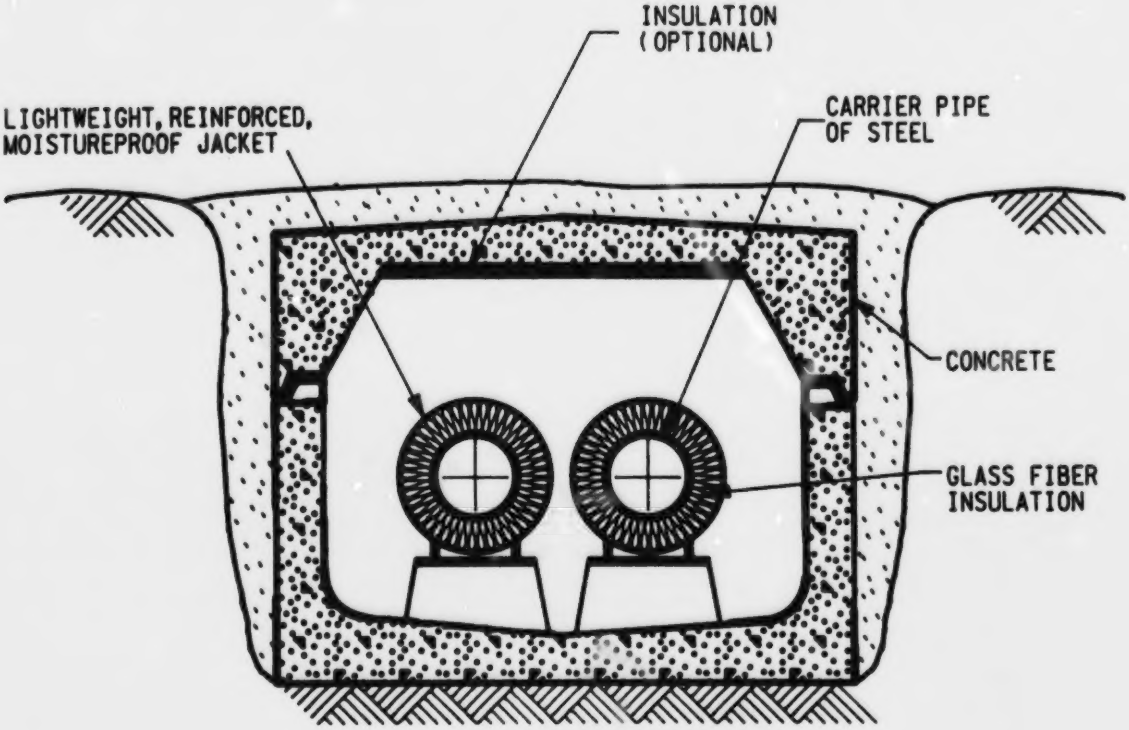
CONSTRUCTION DETAIL


BACKFILL
SAND

INSTALLATION DETAIL

FIGURE 7-7
PRE-INSULATED PIPE SYSTEM
CONSTRUCTION AND INSTALLATION DETAIL

[100,77]DSS77 .DGN

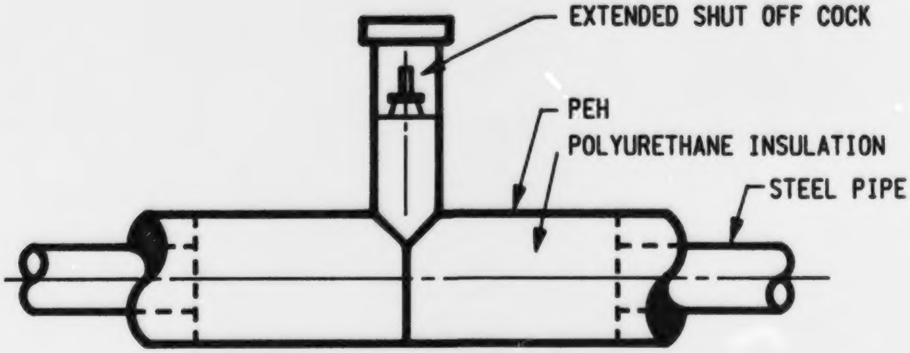

INSULATION (OPTIONAL)
LIGHTWEIGHT, REINFORCED, MOISTUREPROOF JACKET
CARRIER PIPE OF STEEL
CONCRETE
GLASS FIBER INSULATION

NOTE:

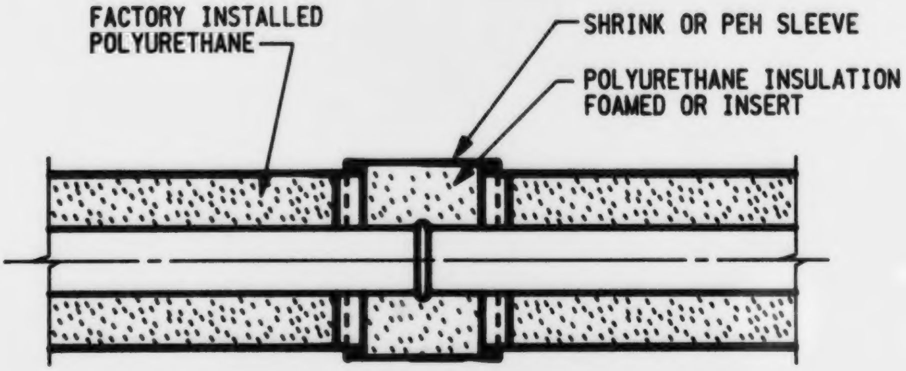
CULVERTS ARE NORMALLY USED FOR PIPE DIAMETERS GREATER THAN 600 mm.
EUROPEAN TYPE PIPE MAY BE USED DEPENDING UPON COST, LENGTH, SOIL CONDITIONS, ETC.

FIGURE 7-8
CONCRETE CULVERT
INSTALLATION DETAIL

[100,77]DSS78 .DGN


EXTENDED SHUT OFF COCK
PEH
POLYURETHANE INSULATION
STEEL PIPE

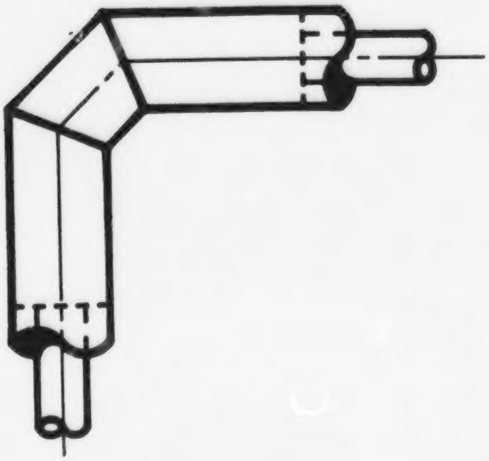
ISOLATION VALVE


FACTORY INSTALLED POLYURETHANE
SHRINK OR PEH SLEEVE
POLYURETHANE INSULATION FOAMED OR INSERT

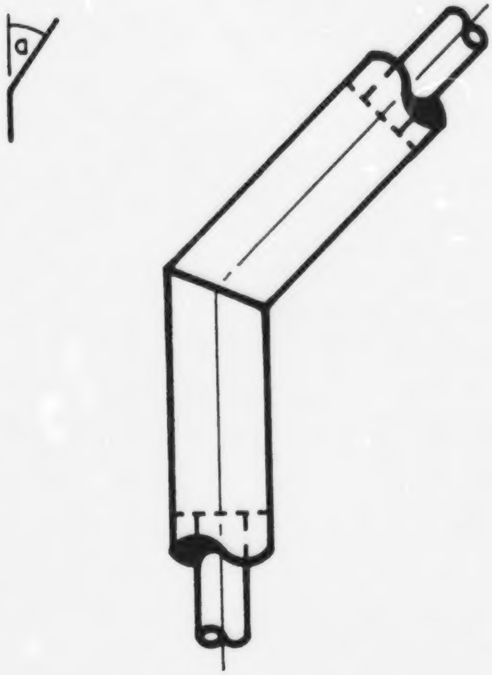
JOINT DETAIL

[100,77]DSS79 .DGN

FIGURE 7-9
PIPE FITTINGS



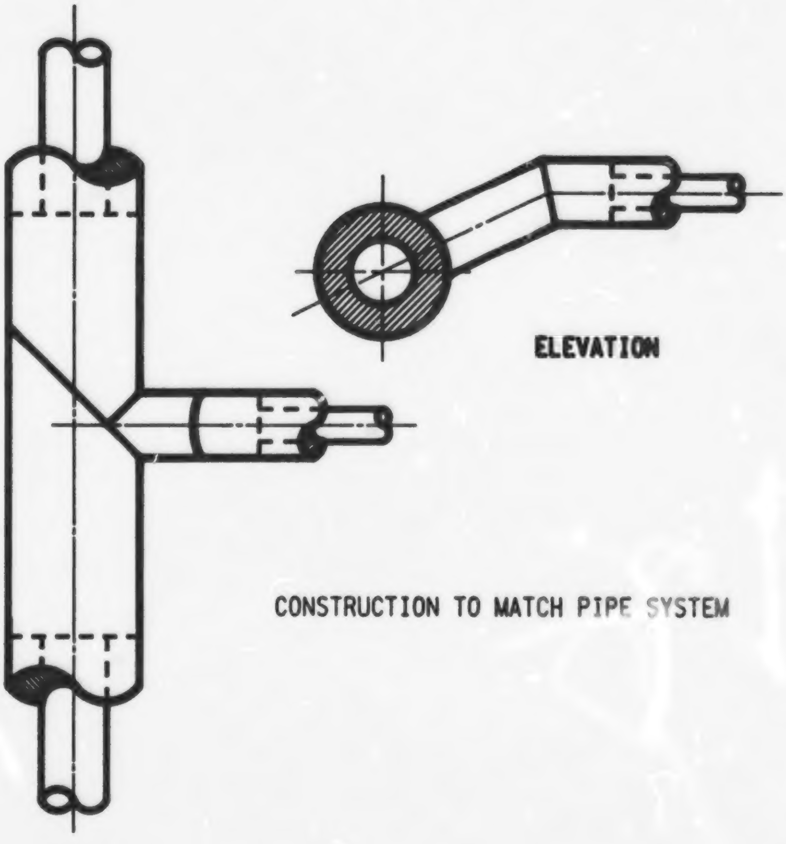
90° PIPE BEND



60°, 45°, 30°, 15° PIPE BENDS
CONSTRUCTION TO MATCH PIPE SYSTEM

FIGURE 7-10
PIPE FITTINGS

[100,77]DSS710 .DGN

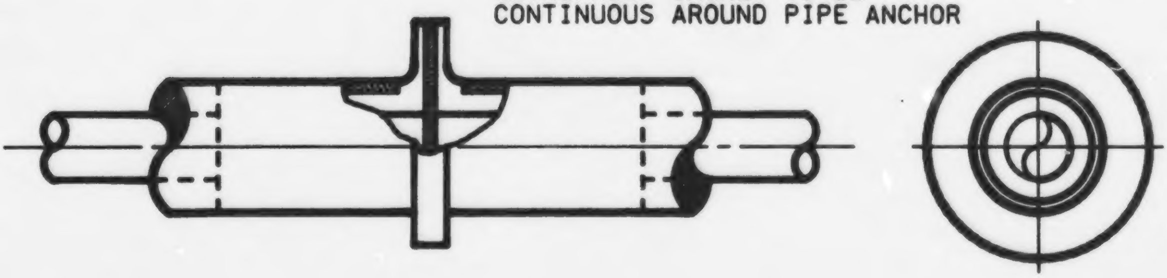

CONSTRUCTION TO MATCH PIPE SYSTEM

PLAN

ELEVATION

T-SECTION

WATREPROOF JACKET TO BE
CONTINUOUS AROUND PIPE ANCHOR



PIPE ANCHOR

FIGURE 7-11
PIPE FITTINGS

[100,77]DSS712 .DGN

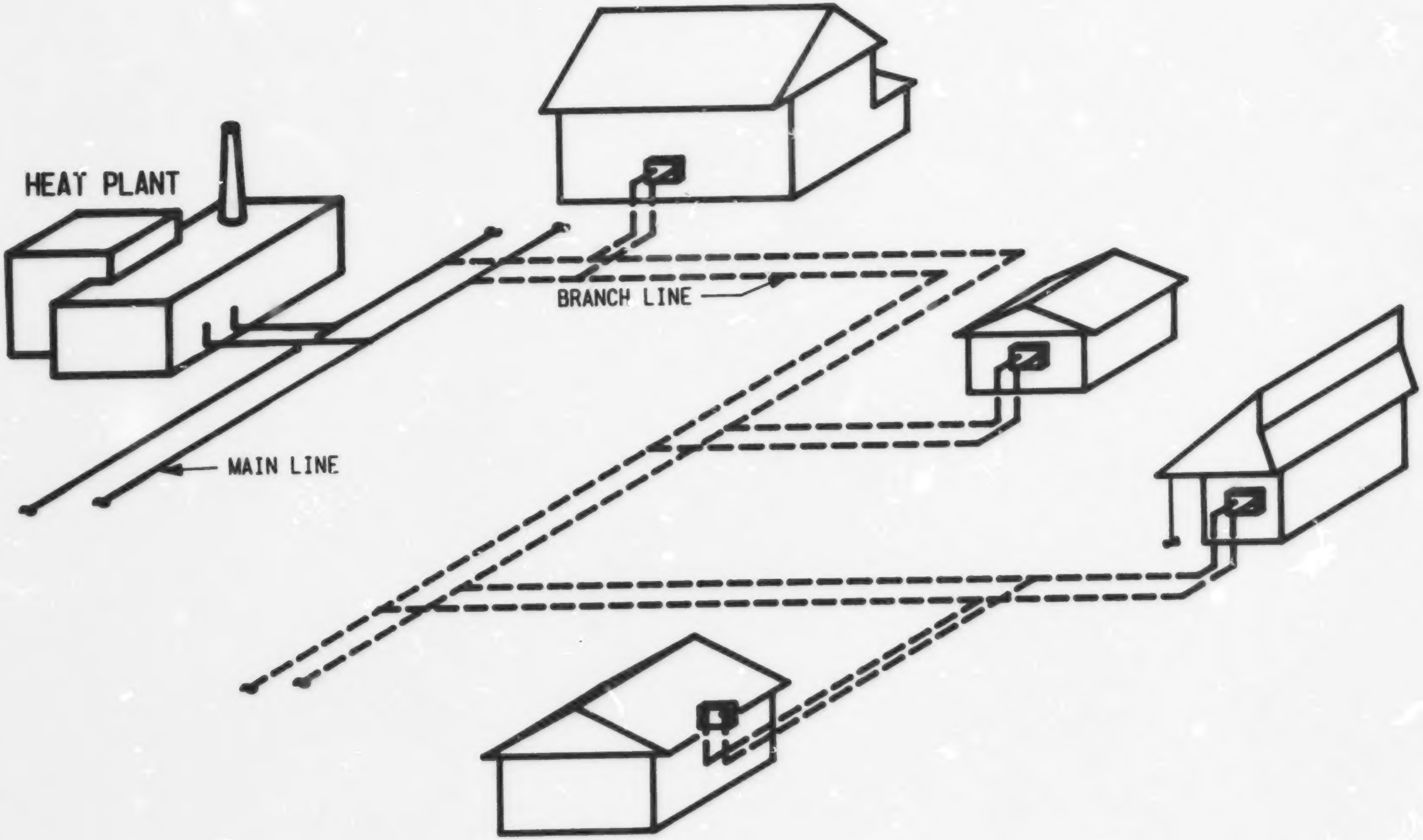

HEAT PLANT
BRANCH LINE
MAIN LINE

FIGURE 7-12
DISTRIBUTION NETWORK

labour and therefore are attractive in a country where labour costs are high.

An additional feature of the European DH piping system is a leak detection and alarm system which is capable of detecting and locating pipeline leaks. Leaks can be located to within a meter of their location, and consequently can be examined and repaired efficiently and economically.

7.5 DISTRIBUTION NETWORK PREDESIGN

751 SELECTED AREAS FOR PREDESIGN

The cost of a distribution network varies greatly with various types of buildings and different building densities. In order to evaluate these differences, low, medium and high heat density areas have been selected for analysis to represent a variety of locations where district heating could be considered. For each area, a predesign has been performed and costs for the distribution network have been determined.

The low heat density area consists of 180 single family houses in a total area of 0.123 km^2 and therefore is an area where each building is located on a relatively large lot. This area is a proposed development in Nepean, Ontario, and is representative of existing low density areas. It is assumed that each building has a maximum heat demand of 15 kW.

The medium heat density area is represented by a part of downtown Halifax as described in a district heating study completed in 1977 [222]. The study describes the situation in the mid-seventies. Consequently, the area represents a downtown area where the heat density is relatively low. The demand of each building varies between 15 and 2,200 kW. It has been assumed that the main pipe running through this area also supplies heat to buildings beyond the selected area. This slightly increases the size of the main.

The high heat density area is represented by the downtown core of Montreal. The area has a very high heat density that is exceeded in few areas in Canada. The information on the area was obtained from a DH study completed in June, 1980 [135]. The study provides only the total heat demand of the buildings so it was assumed for purposes of this study that each end user has the same heat demand - 6 MW. The total demand in the area is 198 MW. The characteristics of these representative areas are shown in Table 7-1.

TABLE 7-1

Variation of Heat Related Data with Heat Density

	Heat Density		
	Low	Medium	High
Total demand - MW	1.83	26.3	198
Total Energy - TJ/a	17.8	251	1782
Area - km^2	0.123	0.35	0.38
Heat Density - MJ/m^2*a	145	717	4689
Number of Connections	122	62	33
Connection Density - $\#/km^2$	991	177	87
Average Connected Load - kW	15	149	6000

752 DESIGN CRITERIA

The predesign in the three selected areas is based on two different temperature drops; 45 and 55°C, reflecting a low temperature system and a medium temperature system. The maximum total pressure assumed is 1.6 MPa. This will normally restrict the available pressure drop in the distribution and subscriber systems to approximately 1.0 MPa. The pressure drop in the production plant and an allowance for elevation differences has been taken into consideration. The design minimum pressure drop at the subscriber substations is 150 kPa. The existence of valves, bends, etc. increases the pressure drop and has been treated by increasing the pipe lengths by 15 percent. Table 7-2 shows the design velocity and capacity for various pipe dimensions. The capacities are calculated for a temperature drop of 55°C and must be reduced by approximately 20% if a temperature drop of 45°C (at a constant velocity) is used.

As discussed earlier, a diversity factor of 80 percent is often used in Sweden. There is no information available on such factors in Canada and for purposes of the study, a diversity factor of 80 percent has been assumed in the design of the main network in the high and medium heat density areas. A diversity factor of 100 percent was assumed for the low density area on the basis that a lower diversity factor would have little effect on pipe costs and installation costs for small diameter pipe are essentially independent of pipe diameter.

753 PREDESIGN OF DISTRIBUTION SYSTEMS

The design of the distribution networks was performed in four steps. The first step was the layout of the network to minimize the piping cost. In all cases, it has been assumed that the pipes are buried in the streets. The second step was the design of the mains

TABLE 7-2

Approximate Heat Transport Capacity of Pipe of Various Diameters for a 55°C Temperature Drop

Nominal Diameter (mm)	Design Velocity (m/s)	Capacity (MW)
25	0.6	0.09
32	0.8	0.20
40	0.9	0.30
50	1.0	0.54
65	1.2	1.10
80	1.3	1.60
100	1.4	2.90
125	1.5	4.70
150	1.6	7.30
200	1.8	14.0
250	2.0	24.0
300	2.3	40.0
400	2.5	68.0
500	2.7	120.0
600	3.0	191.0
700	3.0	262.0

and the larger service pipes. The mains were divided into sections based on the demands of the buildings connected to it. Therefore, as the subscriber's demand decreases, the size of the main decreases. Smaller subscribers along a section of the mains were treated as one connection and service pipes to larger subscribers were included in this part of the design. The next step was to design the system according to the demand at each connection point and the design criteria. The final step was to check the larger mains in order to determine whether or not the diversity factor would permit a smaller pipe. The remaining service pipes were then designed according to the demand and the velocity of the water. The network layouts, divided into sections of uniform pipe diameter, for the high, medium and low heat density areas are shown in Figures 7-13 to 7-15. with the corresponding length and pipe dimension of each section given in Tables 7-3 to 7-5.

754 PREDESIGN RESULTS

The difference between a design temperature drop of 55°C and 45°C is reflected in the required mass flow of the heat transfer fluid. The decreased temperature drop must be compensated for by an increased flow if an equivalent amount of heat is to be transported. The 45°C alternative requires a flow rate which is about 20 percent greater than the system with a temperature drop of 55°C, assuming a constant velocity.

Table 7-6 shows the total length of each diameter used in the three areas with a temperature drop of 45°C and 55°C. The mains and the service pipes are presented separately in the table.

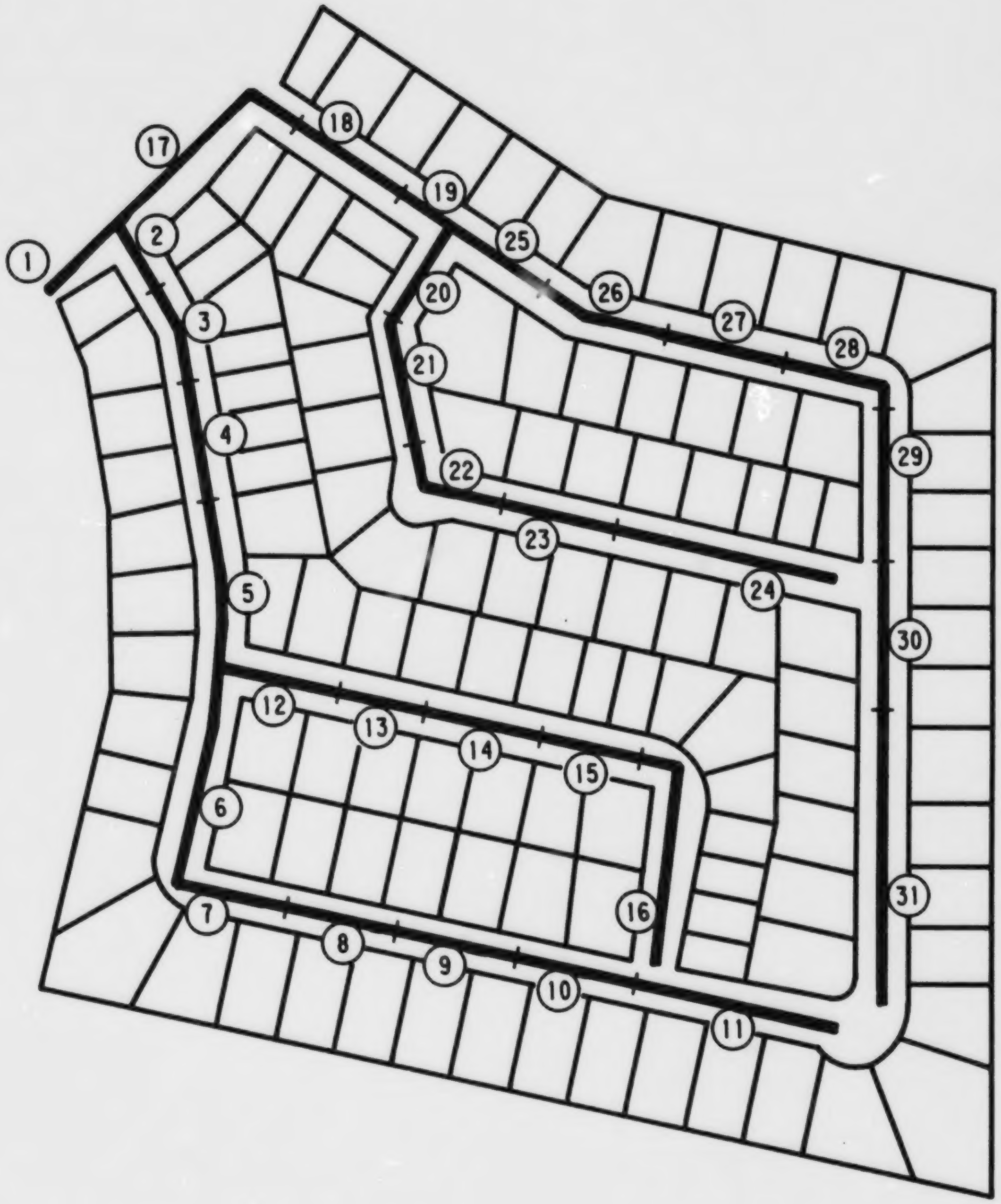

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FIGURE 7-13
DISTRIBUTION SYSTEM FOR
LOW HEAT DENSITY REGION

[100,77]DSS713.DGN

TABLE 7-3

Low Density Area Piping Requirements

Section Number	Length	Nominal Diameter 45°C	Nominal Diameter 55°C
	(m)	(mm)	(mm)
1	50	100	100
2	23	65	65
3	32	65	65
4	43	65	65
5	65	65	65
6	85	50	50
7	39	50	40
8	50	40	40
9	43	40	32
10	54	32	32
11	74	25	25
12	34	50	50
13	43	50	40
14	46	40	40
15	40	32	32
16	70	32	32
17	75	65	65
18	37	65	65
19	29	65	65
20	40	50	50
21	50	50	40
22	43	40	40
23	50	32	32
24	63	32	32
25	40	65	50
26	52	50	50
27	50	50	50
28	43	50	40
29	62	40	40
30	56	40	32
31	81	32	32
Total Length	1562		

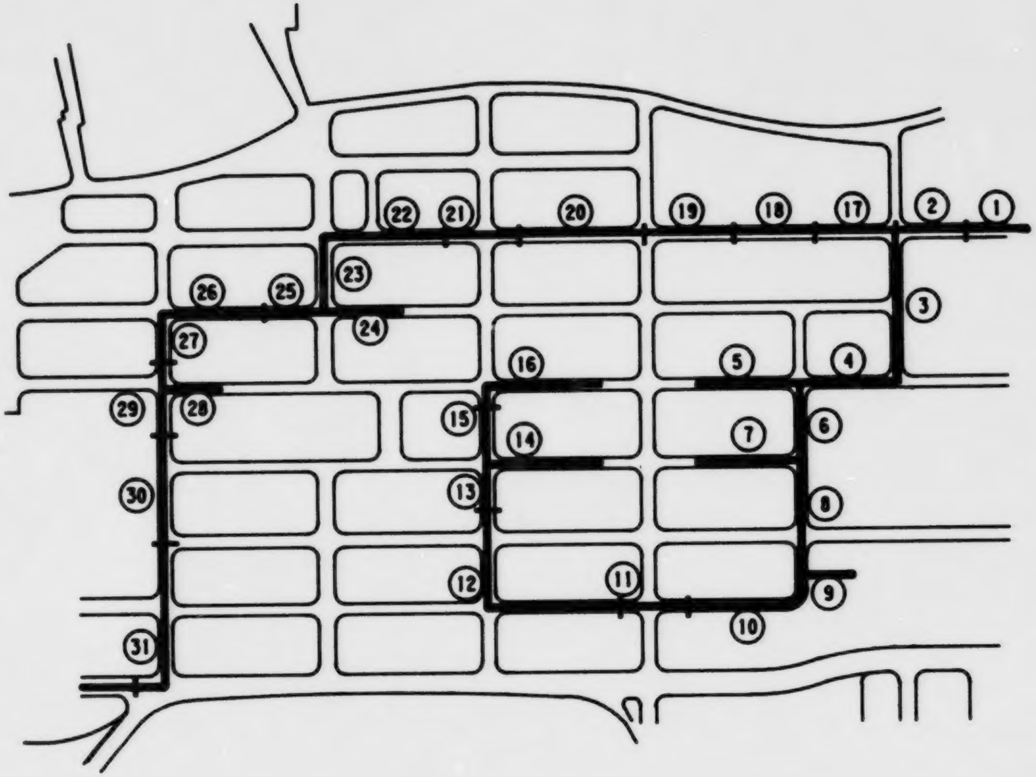
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FIGURE 7-14
DISTRIBUTION SYSTEM FOR
MEDIUM-HEAT DENSITY REGION

TABLE 7-4

Medium Heat Density Area Piping Requirements

Section Number	Length	Nominal Diameter 45°C	Nominal Diameter 55°C
	(m)	(mm)	(mm)
1	42	300	250
2	46	250	250
3	112	200	150
4	69	150	150
5	90	65	65
6	61	150	150
7	61	150	150
8	83	150	150
9	77	65	50
10	92	150	125
11	69	150	125
12	160	125	125
13	30	125	100
14	61	50	50
15	76	80	65
16	61	65	50
17	69	250	250
18	50	250	200
19	61	250	200
20	107	250	200
21	27	250	200
22	77	200	200
23	61	200	200
24	60	65	65
25	77	200	200
26	38	200	200
27	33	200	150
28	40	100	100
29	33	200	150
30	91	150	125
31	175	80	65
Total Length	2189		

[100,77]DSS715 .DGN

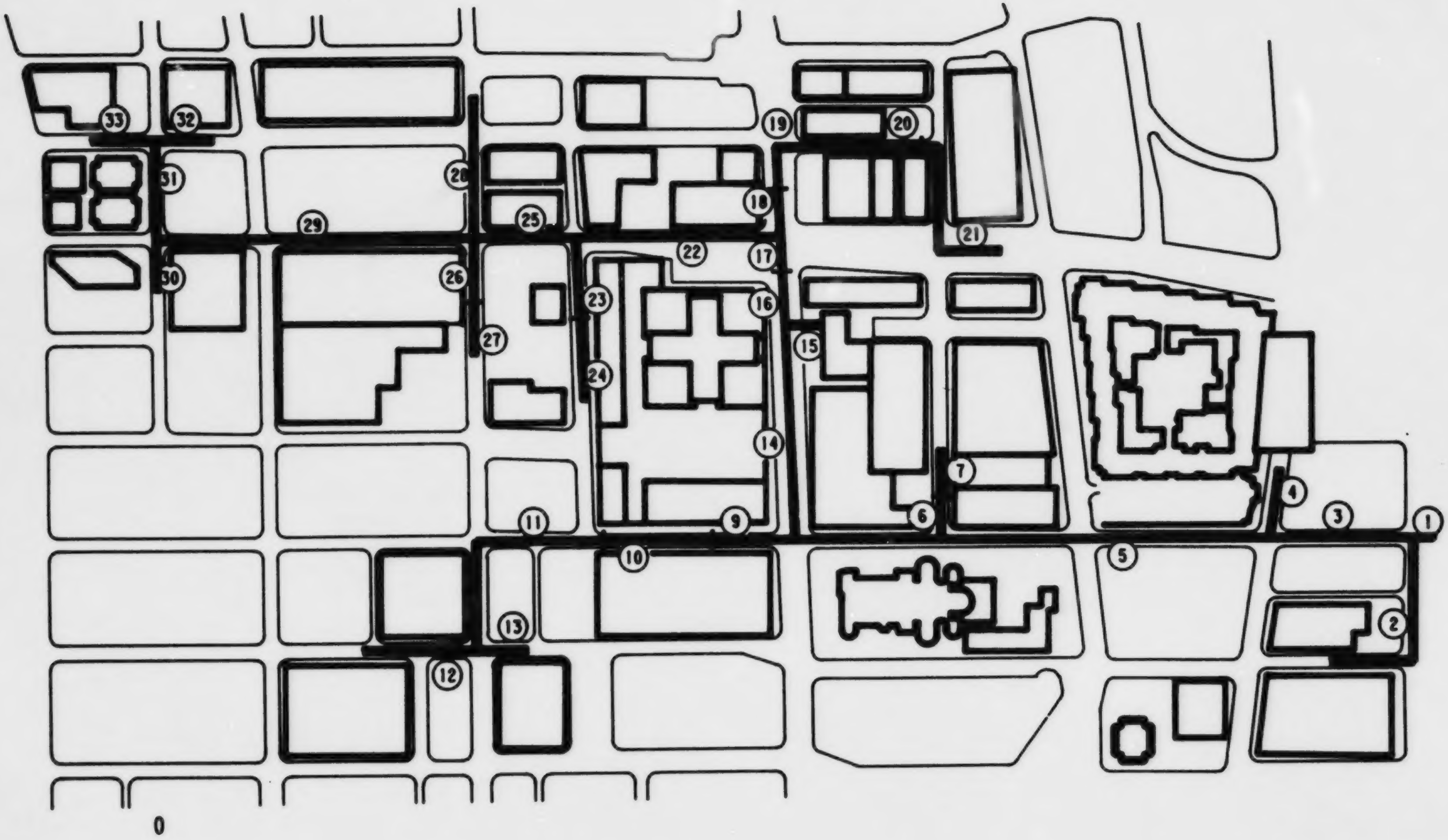
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FIGURE 7-15
DISTRIBUTION SYSTEM FOR
HIGH HEAT DENSITY REGION

TABLE 7-5

High Heat Density Area Piping Requirements

Section Number	Length	Nominal Diameter	
		45°C	55°C
	(m)	(mm)	(mm)
1	61	700	600
2	157	250	200
3	116	700	600
4	76	200	150
5	248	700	600
6	19	250	250
7	56	250	200
8	120	600	600
9	48	300	300
10	88	250	250
11	184	250	250
12	72	250	200
13	61	200	150
14	176	600	500
15	36	200	150
16	20	500	500
17	44	500	500
18	32	300	300
19	84	300	300
20	72	250	250
21	116	250	200
22	156	400	400
23	38	250	250
24	88	200	150
25	80	400	300
26	36	250	200
27	76	200	150
28	112	200	150
29	252	300	250
30	37	250	200
31	77	250	250
32	37	250	200
33	54	200	150
Total Length	2929		

TABLE 7-6

Distribution Pipe Dimensions for 45°C and 55°C Temperature Drop

Nominal Diameter	Low Heat Density Area		Medium Heat Density Area		High Heat Density Area	
	45°C	55°C	45°C	55°C	45°C	55°C
(mm)	(m)	(m)	(m)	(m)	(m)	(m)
Mains						
25	74	74	-	-	-	-
32	358	457	-	-	-	-
40	300	376	-	-	-	-
50	436	301	61	199	-	-
65	344	304	288	401	-	-
80	-	-	251	-	-	-
100	50	50	40	70	-	-
125	-	-	190	412	-	-
150	-	-	526	452	-	503
200	-	-	431	498	415	511
250	-	-	360	157	989	730
300	-	-	42	-	416	244
400	-	-	-	-	324	156
500	-	-	-	-	64	240
600	-	-	-	-	296	545
700	-	-	-	-	425	-
Total Length	1562	1562	2189	2189	2929	2929
Services						
25	1464	1464	215	270	-	-
32	-	-	188	157	-	-
40	-	-	156	166	-	-
50	-	-	181	154	-	-
60	-	-	219	241	-	-
80	-	-	33	152	-	-
100	-	-	371	243	-	-
125	-	-	20	-	-	-
150	-	-	-	-	-	801
200	-	-	-	-	801	-
Total Length	1464	1464	1383	1383	801	801

The table shows the consequences of the higher mass flow in the network with a temperature drop of 45°C. The length of the larger diameter pipes increases and the length of the smaller pipes decreases compared to the same system with a 55°C temperature drop. Pipes that are close to their maximum capacity in the case of the 55°C temperature drop must be increased to the next largest standard diameter pipe when the design is based on a 45°C temperature drop. For example, it can be seen that in the low density area, the lengths of the smaller diameter pipes (32 and 40 mm) decrease while the lengths of the larger diameter pipes (50 and 65 mm) increase.

7.6 DISTRIBUTION NETWORK CAPITAL COSTS

761 GENERAL

It has been assumed that transmission and distribution network piping will be constructed with factory assembled preinsulated piping systems of the type discussed in Section 742 which have a proven performance record. Investigation has indicated that traditional Canadian and United States suppliers of factory insulated pipe are not manufacturing this type of pipe system but it is expected that if there were a demand for such pipe, they would make the necessary production arrangements. A large Finnish firm has manufacturing facilities in Ontario capable of producing this type of pipe and a large Swedish firm has recently purchased a plant in the United States with the intention of producing factory insulated pipe.

Discussions have taken place with Canadian steel pipe manufacturers regarding the production of thin wall pipe (Schedule 20). While Schedule 10 pipe is manufactured for the sprinkler industry, Schedule 20 pipe is not currently manufactured. Provided there is sufficient demand, manufacturers have indicated a capability and a willingness to produce Schedule 20 pipe.

The type of pipe system for the distribution network and the transmission system are identical. However, the number of valves, fittings and anchors used are different with, for example, few valves and tees required for transmission lines.

762 DISTRIBUTION NETWORK

The price of pipe systems for diameters of 20 to 250 mm inclusive was obtained from the Finnish firm previously mentioned. Price information was obtained for different classes of insulation, valves and fittings, leak detection and alarm devices, joining sleeves, and insulation prices for the joints. The price of pipe was based on Schedule 40 pipe because the steel companies do not yet manufacture Schedule 20 pipe as a standard item. Prices were not requested of other firms that manufacture factory insulated pipe because none manufacture European type pipe in Canada.

Prices for pipe systems are not available for pipe diameters greater than 250 mm; consequently, these have been estimated.

Discussions were held with mechanical and general contractors to develop installation and civil costs. Price estimates were developed for 100 m of pipe, assuming a shallow burial, two pipe system. It was assumed that a tee would be installed every 50 m with an expansion loop and anchor for every 100 m. An allowance of 20 percent was provided for installation of joining sleeves and valves. The estimated total cost of installing distribution piping in greenfield conditions and expressed in 1984 Canadian dollars is presented in Table 7-7. These costs were adjusted by the multipliers shown in Table 7-8 to reflect the estimated additions to pipe installation costs and civil works when constructing a distribution system in other than greenfield conditions. These factors have been applied in Table 7-9 to develop the total estimated cost of installing distribution piping in downtown conditions.

These cost estimates were checked for reasonableness against other cost estimates and actual costs and the results are shown on Figure 7-16. Swedish costs have been checked to ensure that installations were comparable and the only difference would appear to be the cost associated with thin wall pipe. The costs developed in this study do not include the contingency factors which were used to develop the costs for the Edmonton study however, the Edmonton costs were increased to reflect escalation from 1982 to 1984 [228]. The St. Paul costs appear high and likely included a substantial contractor contingency to allow for inexperience, particularly since this work was awarded on a fixed price lump sum contract basis [111].

In view of the much lower costs in Sweden, and the manufacturing capability that appears to be developing in the United States and Canada, it is considered that the prices developed for this study are realistic.

TABLE 7-7

Distribution Piping Costs for Double Pipe System in Greenfield Conditions
(1984 $ Cdn)

Nominal Diameter (mm)	Material Cost ($/m)	Installation Cost ($/m)	Civil Costs ($/m)	Total Installed Cost ($/m)
25	36	24	68	128
32	43	28	68	139
40	45	29	68	142
50	56	38	68	162
65	64	38	68	170
80	75	60	68	203
100	102	72	68	242
125	128	89	68	285
150	154	106	75	335
200	249	134	75	458
250	357	192	75	624
300	393	210	102	705
400	522	280	102	904
500	653	350	136	1139

TABLE 7-8

Cost Multipliers for Other than Greenfield Conditions

Area	Material Factor	Installation Factor	Civil Works Factor
Open Areas	1.0	1.0	1.1
Single Family Dwellings	1.0	1.05	2.16
Apartment Buildings	1.0	1.15	3.45
Downtown Areas	1.0	1.20	3.79

TABLE 7-9

Distribution Piping Costs for Double Pipe System in Downtown Conditions
(1984 $ Cdn)

Nominal Diameter (mm)	Material Cost ($/m)	Installation Cost ($/m)	Civil Costs ($/m)	Total Installed Cost ($/m)
25	36	29	258	323
32	43	34	258	335
40	45	35	258	338
50	56	46	258	360
65	64	46	258	368
80	75	72	258	405
100	102	86	258	446
125	128	107	258	493
150	154	127	284	565
200	249	161	284	694
250	357	230	284	871
300	393	252	386	1031
400	522	336	386	1244
500	653	420	515	1588

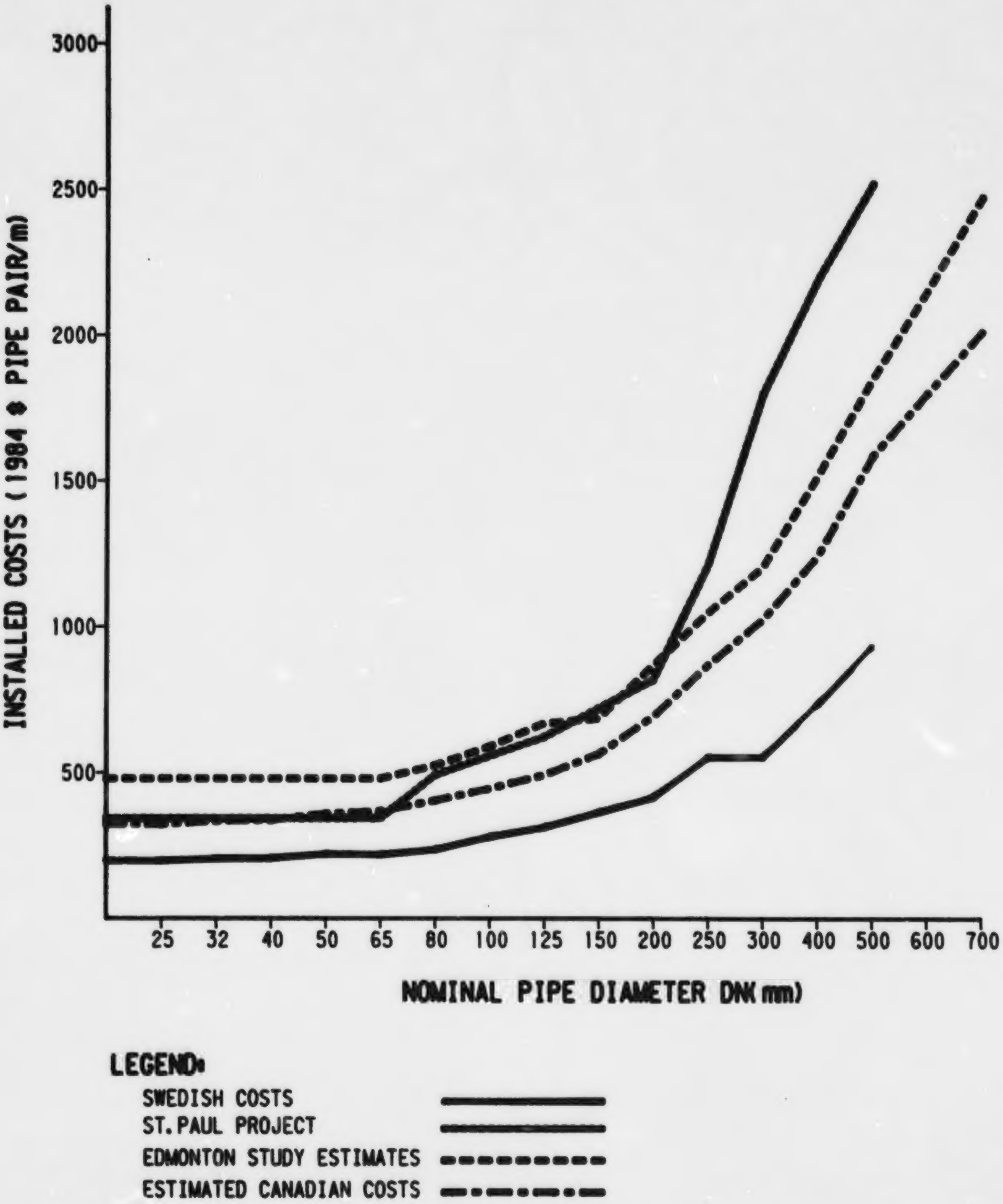


FIGURE 7-16
COMPARISON OF COSTS FOR INSTALLED PIPE

[100,77]DSS716 .DGN

7.7 TRANSMISSION SYSTEM CAPITAL COSTS

Transmission systems usually consist of long pipe runs and the only fittings required are anchors and some type of expansion devices. Expansion compensators and preheating of pipe have been used in Europe with some success but expansion loops are usually preferred unless there are space limitations.

The unit cost of the transmission pipe was calculated using a distance of three km. to allow for the various components such as anchors and loops that would be required for the system. The estimated total cost of installing transmission piping for open and residential areas is presented in Table 7-10.

TABLE 7-10

Transmission Piping Costs for
Double Pipe System
(1984 $ Cdn)

Nominal Diameter	Total Installed Cost Open Area	Total Installed Cost Residential Area
(mm)	($/m)	($/m)
200	441	526
400	862	983
500	1089	1249
700	1336	1631

7.8 RELATIONSHIP BETWEEN HEAT DENSITY AND DISTRIBUTION COST

A preliminary design was performed and cost estimates developed for three areas which reflect a range of heat densities. Each area has different specific characteristics such as connection density and heat density. Assuming that these specific characteristics are representative of the different heat densities, it is possible to draw some general conclusions from the results regarding the relationship between heat densities and distribution costs. The result has been plotted on a graph showing heat densities and estimated capital costs per GJ of energy consumed. The capital costs are based on the estimates for the 55°C temperature drop system. To improve the accuracy of the graph alternative designs were performed for the selected areas with higher and lower flows of the heating fluid to reflect increased and decreased heat demand relative to the initial heat loads. Figure 7-17 shows the results of this analysis with a blown-up section for the low density areas.

The graph also shows the relationship between estimated capital costs and heat densities for both greenfield and built-up areas. The graph is suitable for preliminary cost estimates of district heating networks but site specific information including such factors as ground conditions and actual connection density must be considered when estimating costs for a more detailed district heating design at a specific location.

Although the graph does not include a number of factors that must be considered for a given site, it clearly indicates a large change in the unit cost as the heat density changes. The heat densities represent the values that would be expected in a typical residential area (low density), a city of average construction such as Saskatoon, Kingston, or Halifax (medium density), and a city core of large office buildings such as found in Montreal, Toronto or Vancouver (high density).

[100,77]DSS717 .DGN

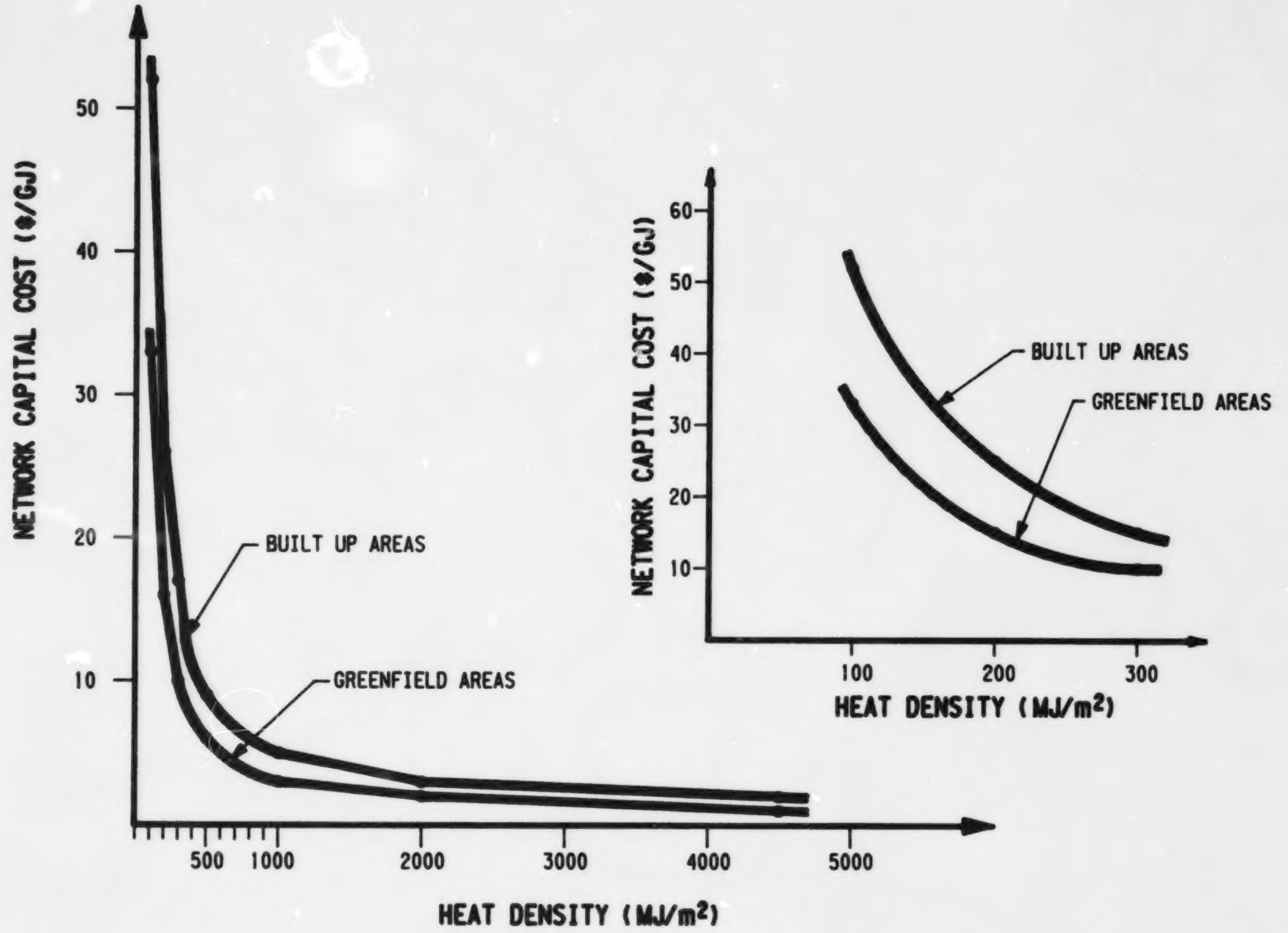


FIGURE 7-17
NETWORK CAPITAL COST vs HEAT DENSITY

The estimated capital cost in a high density area (more than 1000 MJ/m^2) is less than \$5/GJ in built-up areas and less than \$2.5/GJ in greenfield areas. The specific costs increase rapidly with decreasing heat densities such that when the heat density is reduced to 100 MJ/m^2, the specific capital cost is of the order of \$50/GJ and \$30/GJ for built-up and greenfield areas respectively.

7.9 LOW AND MEDIUM TEMPERATURE SYSTEM CAPITAL COSTS

The low temperature networks are more expensive for all three sites than are the medium temperature networks. Table 7-11 shows the costs for each temperature drop for each heat density in greenfield and built-up areas. The largest cost difference occurs in the high heat density area. About one-third of this difference is the result of having to increase the size of the service mains. As discussed previously, it has been assumed that each building has an equal heat demand and consequently the service pipe to every building will be increased in size. Therefore this portion of the costs will tend to be over-estimated because the heat demand for actual installations will change from building to building with the likely result that only some of the service pipes will have to be increased in diameter. For the medium heat density area, the capital cost difference is 6 and 9 percent for the built-up and greenfield areas respectively, while for the low density area, there is essentially no difference in capital cost between the two different temperature systems for both the built-up and greenfield areas.

There are several reasons for the variation in cost differences between the three heat density areas. When the diameter of a small pipe is increased by one size, the change in potential capacity is larger than if a pipe of a large diameter is increased by one size. Therefore, the amount of pipe that will require an increase in pipe size in the low density area is less than in the other areas. In addition the cost for the service pipes in the low density area does not change because the smallest pipe used has sufficient capacity for either temperature.

Another factor that influences the installation cost is the scale factor associated with the cost of the pipe systems of the larger sizes. An increase of one size of a small pipe results in a much smaller cost increase than is the case for an increase of one size in a larger pipe.

TABLE 7-11

Capital Costs of Distribution Net Works
for Three Heat Densities
($'000)

	Low Heat Density Area		Medium Heat Density Area		High Heat Density Area	
	45°C	55°C	45°C	55°C	45°C	55°C
Greenfield Area						
Mains	251	248	802	712	2245	2007
Services	187	187	241	235	367	268
Total	438	435	1043	947	2612	2275
Specific Cost ($/GJ)	24.6	24.4	4.2	3.8	1.5	1.3
Built-up Area						
Mains	370	367	1294	1191	3072	2800
Services	304	304	522	510	556	453
Total	674	671	1816	1701	3628	3253
Specific Cost ($/GJ)	37.9	37.7	7.2	6.8	2.0	1.8

7.10 THE EFFECT OF CONNECTION DENSITY ON DISTRIBUTION CAPITAL COSTS

The three areas selected in Section 751 have a wide range of connection densities, varying by a factor of more than ten times between the low density and high density areas. The large number of connections in the low density area is the main reason why service piping accounts for almost 50 percent of the total cost of the distribution network compared to 15 percent for the high density area.

The following example shows the impact of an increasing connection density on the total length of a distribution network. The example is based on an area of 0.21 km^2. The total length of the network has been calculated for three alternatives, each with an increasing number of connections. Each service pipe has been assumed to have a length of 12 m and the distance between buildings assumed to be 24 m. Sections of the layouts of distribution networks to be compared are shown in Figure 7-18.

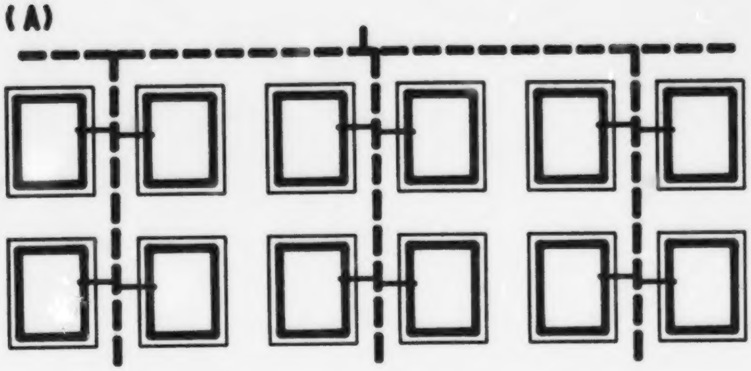
Alternative A reflects a system that serves a given area where the buildings cover the entire block. In B, each block contains two buildings and in C, four buildings. The physical differences among these alternatives is shown in Table 7-12. The examples assume twenty-four blocks in each case.

TABLE 7-12

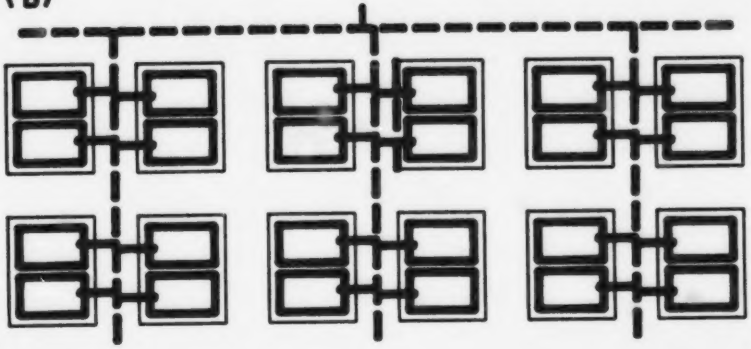
Lengths of Distribution Piping
for Three Connection Densities

Characteristics	Examples		
	A	B	C
Number of connections	24	48	96
Connection density (#/km^2)	113	227	455
Length: Mains (m)	1,640	1,800	3,560
Service pipes (m)	288	576	1,152
Total length (m)	1,928	2,376	4,712

ALTERNATIVE (A)



ALTERNATIVE (B)



ALTERNATIVE (C)

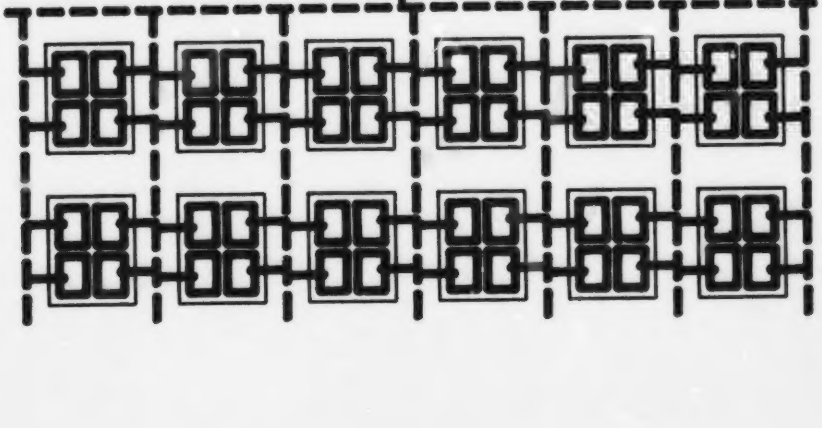


FIGURE 7-18
CONNECTION DENSITY

[100,77]DSS718 .DGN

A general observation is that the length of the mains increases in relation to the number of streets serviced, whereas the length of the service pipes is determined by the number of connections. If the total demand were the same for examples A, B and C; the size of the pipes in some parts of the network would be reduced as the number of connections increased. In comparing example B to A and example C to B, parts of the mains and all of the service pipes will carry a smaller amount of heat and consequently, could be designed with smaller dimensions. However, as the unit cost of pipe capacity is inversely affected by a factor of scale, the decrease in pipe size and cost does not compensate for the increased length of the network. For example, the cost of installing a unit length of 80 mm pipe is 84 percent of the cost of a unit length of 100 mm pipe although the capacity of the 80 mm pipe is only 55 percent of that of the 100 mm pipe. Therefore the length of piping required has a much greater influence on cost than does pipe diameter.

The impact on the distribution network capital costs of a change in connection density has been examined for the selected areas. The analysis is based on the 55°C temperature drop and assumes that the number of connections is doubled in each area. Each subscriber therefore has half the original demand and the pipe size will normally decrease one diameter from those used in the cost calculations of Table 7-11. In the low density area, however, the pipe diameters cannot be reduced because the service pipes initially assumed for this area are the smallest diameters used for district heating networks. The physical consequence of increased connection density is an increase in the total length of service piping. This is reflected in the capital cost analysis shown in Table 7-13.

TABLE 7-13

Effect of Increased Connection Densities on
Distribution Network Capital Costs

	Low Heat Density Area	Medium Heat Density Area	High Heat Density Area
	($'000)	($'000)	($'000)
Built-up Area (55°C)			
Mains	383	1,191	2,800
Services	762	1,022	790
Total	1,145	2,113	3,590
Percent increase in capital costs (reference Table 7-11)	70	24	10

It is clear that a change of the number of connections has a large impact on the capital costs for the distribution system in the low density area and the impact tends to diminish with increasing heat density.

7.11 THE EFFECT OF MARKET PENETRATION ON DISTRIBUTION CAPITAL COSTS

The design of a distribution network is based on the existing demand of buildings in the area where district heating will be implemented. Future developments (known and sometimes assumed) should also be included. Normally heat demands in buildings are included even if the owner has not agreed to connect to the network. The interest in connecting the building tends to increase once the network is built. However, if a large proportion of the total building stock is not connected the cost per unit of heat for the distribution system will increase. Table 7-14 shows how the capital cost for a distribution system increases as the connection percentage decreases. This table is based on a change in the market penetration for the three areas selected for the predesign of the distribution system. In this example it has been assumed that the total cost for service piping increases with market penetration i.e. service pipes are only built when a building is connected to the district heating network.

TABLE 7-14

Effect of Market Penetration on Distribution Network Capital Costs

Market Penetration	Low Heat Density Area	Medium Heat Density Area	High Heat Density Area
(%)	($/GJ)	($/GJ)	($/GJ)
50	58.3	11.6	3.4
75	44.6	8.5	2.3
100	37.7	6.9	1.8

Table 7-14 indicates that low market penetration will have a large impact on the unit capital costs of the distribution network. The increased costs are due to the fact that the mains are designed and built to serve the total heat load, while the unit cost per heat unit delivered depends upon market penetration.

7.12 DISTRIBUTION CAPITAL COSTS FOR THE CANADIAN MODEL

A heat density model of a typical Canadian city was developed in Part 5 of the study and presented in Table 5-6. In the model, a typical Canadian city was divided into four heat density regions: the core; 200 MJ/m^2 and above (excluding the core); 100-199 MJ/m^2; and 0-99 MJ/m^2. Only the first three of these densities are high enough to have the potential to support district heating. In Part 7 of the study the costs of distribution systems have been evaluated using low, medium and high heat density areas to estimate the relationship of distribution network capital costs to heat density. The results of the analyses from these two parts have been combined to provide an estimate of the distribution system capital costs in the different heat density regions of Canadian cities for different climatic conditions. These costs are based on communities with a population between 100,000 and 899,999 inhabitants and 100 percent market penetration for the system. Smaller communities have a smaller heat density in the core, but the costs will change very little as can be seen in Figure 7-17.

The unit capital costs for district heating distribution systems developed from this analysis are presented in Table 7-15. Tables 7-16 and 7-17 provide these costs based on 75 percent and 50 percent market penetration respectively. As would be expected, costs tend to decrease with increasing heat density, increasing degree days, and market penetration. These capital costs are used as input to the economic analysis discussed in Part 9 of the study.

TABLE 7-15

Distribution System Capital
Costs for the Canadian Model
(100 Percent Market Penetration)

	Annual Degree Days	Heat Density (MJ/m^2)		
		100-199	200-core	core
	(°C)	($/GJ)	($/GJ)	($/GJ)
Greenfield Areas	3500	35	19	4.1
	4500	26	15	3.7
	5500	21	13	3.2
Built-up Areas	3500	51	29	6.1
	4500	39	24	5.3
	5500	33	21	4.4

TABLE 7-16

Distribution System Capital Costs for the Canadian Model (75 Percent Market Penetration)

	Annual Degree Days	Heat Density (MJ/m^2)		
		100-199	200-core	core
	(°C)	($/GJ)	($/GJ)	($/GJ)
Greenfield Areas	3500	37	22	4.7
	4500	32	18	4.5
	5500	29	15	4.3
Built-up Areas	3500	65	32	8.5
	4500	50	26	8.2
	5500	40	22	7.7

TABLE 7-17

Distribution System Capital Costs for the Canadian Model (50 Percent Market Penetration)

	Annual Degree Days	Heat Density (MJ/m^2)		
		100-199	200-core	core
	(°C)	($/GJ)	($/GJ)	($/GJ)
Greenfield Areas	3500	50	28	6.0
	4500	42	21	5.7
	5500	33	18	5.5
Built-up Areas	3500	85	50	11.5
	4500	65	37	11.0
	5500	50	26	10.5

7.13 TRANSMISSION CAPITAL COSTS FOR THE CANADIAN MODEL

The unit installed costs for transmission piping of varying diameter have been presented in Table 7-10. Table 7-18 shows how the unit capital cost of transmission piping capacity varies with pipe diameter.

TABLE 7-18

Capacity Costs of Transmission Piping

Nominal Diameter	Heat Capacity	Capacity Unit Costs	
		Open Area	Residential Area
(mm)	(MW)	($/kW*km)	($/kW*km)
200	10	44.1	52.6
400	50	17.2	19.7
500	100	10.9	12.5
700	200	6.7	8.2

Table 7-19 shows how different utilization times affect the capital cost per unit of heat energy for the transmission systems. A utilization time of 3000 hours represents a transmission pipe supplying the total demand whereas a utilization time of 5000 hours represents a transmission system designed to supply only the base load as discussed in Part 7.3.

TABLE 7-19

Capital Cost of Transmission per Unit of Heat Energy

Nominal Diameter	Capacity	Utilization Time	
		3000 hrs	5000 hrs
(mm)	(MW)	($/GJ*km)	($/GJ*km)
200	10	4.1	2.4
400	50	1.6	1.0
500	100	1.0	.6
700	200	.6	.4

It is clear from the table that the capital costs of transmission capacity, expressed in terms of annual energy throughput, decline significantly with increasing diameter and utilization time.

PART EIGHT

SUBSCRIBER HEATING SYSTEMS

PART EIGHT - SUBSCRIBER HEATING SYSTEMS

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FIGURES

FIGURE

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8.1 GENERAL

The subscriber system refers to the heating systems located within the subscriber's dwelling or building. These systems extract heat from the hot water delivered by the DH system for domestic hot water (DHW) and for space heating purposes. The DH system, which usually terminates one metre from the inside building wall with an isolation valve on the supply and return lines, normally includes the meter station. For purposes of this discussion, however, the meter station has been included with the subscriber system.

The temperature program of the DH system will affect the requirements of the subscriber system. A building connected to a DH system supplying MTHW at 120°C must be equipped with water/water and water/air heat exchangers in a mechanical room for safety reasons. There are no such safety restrictions if the building is supplied by LTHW at 90°C and the DH water can be distributed directly to the inhabited areas.

As noted in Part Seven, it is desirable to operate the distribution network at the lowest static pressure that is commensurate with teh saturation temperature of the water. However, this pressure must be adequate to raise the water a few meters above all equipment, heat exhangers and direct connected convertors and coils. If such equipment is located at a high elevation, it would impose a substantial pressure requirement on the network. Therefore, the use of heat exhangers, located near ground level of high rise buildings, is desirable whether it is a LTHW and MTHW system.

In general, building heating systems will consist of separate heat exchangers for space heating and DHW systems. For air handling systems located in a mechanical room, low or medium temperature DH water may be supplied directly to the heating coils.

An important consideration in the design and operation of DH systems is that the temperature drop from the supply to return be as large as possible. Therefore, equipment must be designed to provide a large temperature drop with controls and operating procedures to maintain the temperature drop, especially during periods of cold weather.

Subscriber systems for new buildings connected to DH systems will transmit heat in the form of hot water of hot air. For small buildings such as single family houses, fan coil air units or hot water connectors are both suitable methods of heating. Large apartment and office buildings generally require a form of hydronic and air heating, the latter being necessary for adequate ventilation.

It is a relatively simple task to retrofit existing buildings equipped with hydronic heating and air units which are supplied by a hot water boiler. In this case, the boiler and DHW heaters can be replaced by heat exchangers. On the other hand, buildings heated by electric resistance baseboard or steam which is distributed throughout the building are more difficult and costly to retrofit. The City Hall in St. Paul, Minnesota, was converted from a steam to a hydronic system in 1983. While the cost of the complete conversion, including a significant upgrading of the heating system, was \$25/m^2, the amount directly associated with the conversion was only \$7.50/m^2.

8.2 SUBSCRIBER SYSTEMS

821 OFFICE AND APARTMENT BUILDINGS

The cost of connecting a new office or apartment building to district heating is normally less than the cost to install boilers and associated heating equipment to heat the building using natural gas, oil or electricity. Requirements for mechanical room space and operating and maintenance costs for the DH subscriber system will also be less than for conventional systems. The cost of the secondary systems will be similar regardless of the type of heat source.

In general, existing office and apartment buildings require similar retorfit work to convert to a DH system. Both, generally are equipped with mechanical rooms which can be used to install heat exchangers. However, most apartments do not have the suspended ceilings that exist in office buildings. This will result in more cutting and patching being required and, hence, higher costs for retrofit.

The cost and difficulty of connecting existing office and apartment buildings to a DH system will depend upon the existing method of heating. Conversion of steam heating systems based on the distribution of low pressure steam throughout the building is relatively complex and costly because the system must be retrofitted to be suitable for use with hot water. Condensate lines must be refitted to handle return water and existing pipes may be too small to accommodate return water flow. The steam pipes would likely be satisfactory for hot water with little modification required. Steam coils in air handling units and other heating equipment were often over designed in the past and, therefore, would likely have sufficient capacity for conversion to hot water operations.

When the existing heating system is hydronic, the changes required to connect to a DH system are minimal. Essentially, all that is required is to replace the boilers with heat exchangers. The boiler may be left in place to provide emergency heating.

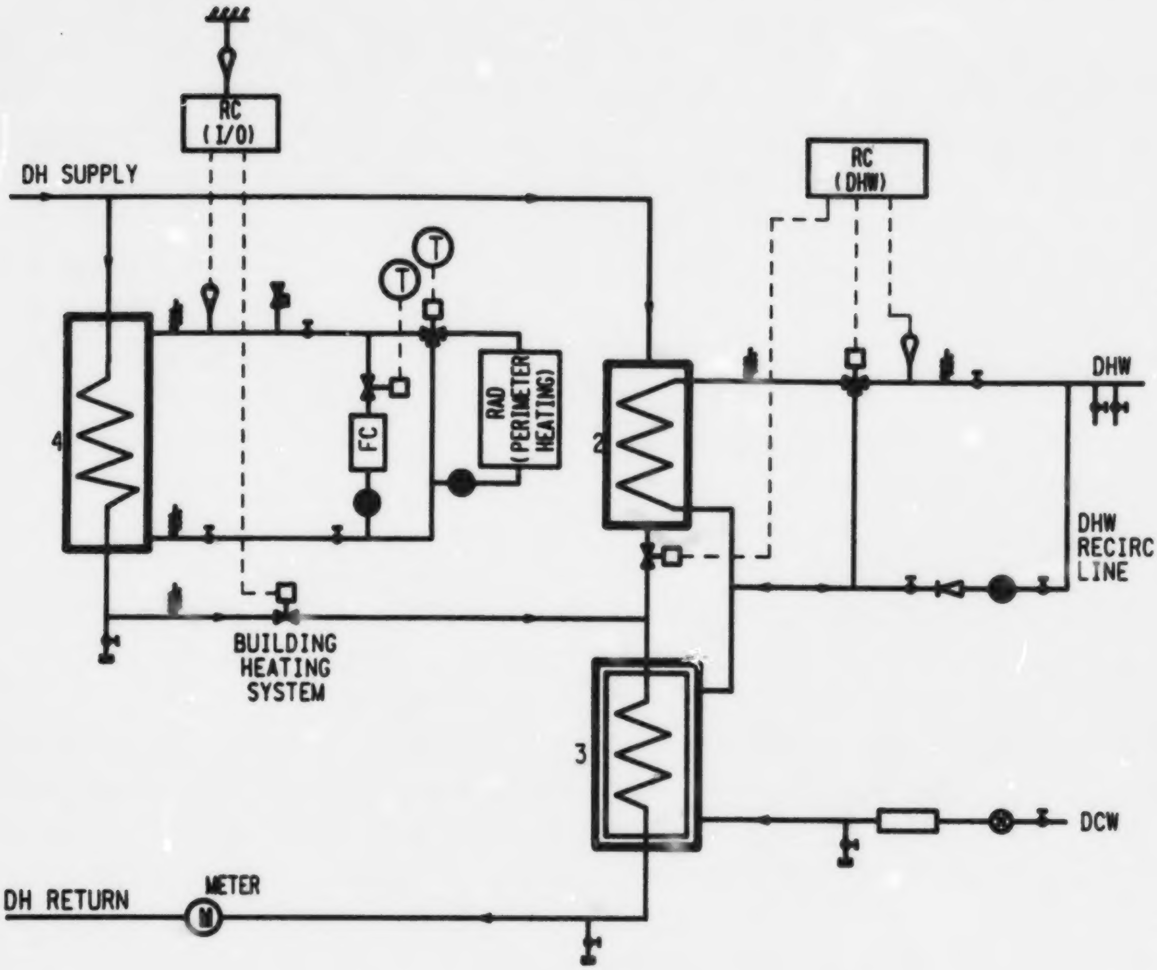
For buildings heated with perimeter electric resistance baseboards and wall mounted electrically heated air systems, retrofit work for conversion to district heating is relatively difficult. It is necessary to install hot water convectors on the perimeter of the building with supply and return pipes installed in vertical chases. Horizontal pipe runs could probably be incorporated into the convector cabinets. This is a practice which has been used frequently in the past.

A central air system could be retrofitted by replacing the electric coil with a water coil. However, apartments and office buildings, equipped with wall mounted electric heating and ventilating units, would require a complete replacement of these systems by a central air and hydronic systems. Consequently, it has been assumed that an electrically heated apartment or office building would require an essentially new heating system and in some instances, a new air supply system for ventilation. The equipment costs would be about the same as for a new building but the installation costs would be significantly higher.

Domestic hot water for these retrofitted buildings would probably be heated most effectively by using a large storage tank with heat exchanger. DHW heating systems in Europe, however, are usually two or three stage heat exchanger arrangements which heat the water as required and do not store DHW as shown in Figures 8-1 and 8-2. There are advantages to using this type of system, but because the common practice in Canada is to use the storage tank, this may be a more suitable method of heating DHW. Both systems should be examined to determine the most suitable method for any particular building; however, it is not expected that there would be a significant cost difference between the two systems.

822 SINGLE DETACHED DWELLINGS AND DUPLEXES

It is recognized that the heating requirements for most single detached dwellings and duplexes will not be the same because the heat losses for the latter are usually smaller than for the single detached house. However, the cost of the heating unit will be


RC (I/O)
DH SUPPLY
RC (DHW)
T
T
4
FC
RAD (PERIMETER HEATING)
2
DHW
DHW RECIRC LINE
BUILDING HEATING SYSTEM
3
DCW
DH RETURN
METER
M

LEGEND

1. TEMPERING VALVE
2. CONVERTOR FOR FINAL HEATING OF DHW.
3. CONVERTOR/STORAGE TANK FOR PREHEATING OF DHW.
4. CONVERTOR FOR HEATING SYSTEM.

T	TEMPERATURE CONTROLLER
FC	FAN COIL
RC	REMOTE CONTROLLER (INDOOR/OUTDOOR OR DHW)
RAD	RADIATOR

FIGURE 8-1
TYPICAL USER SYSTEMS - LARGE BUILDINGS
2-STAGE CONNECTIONS

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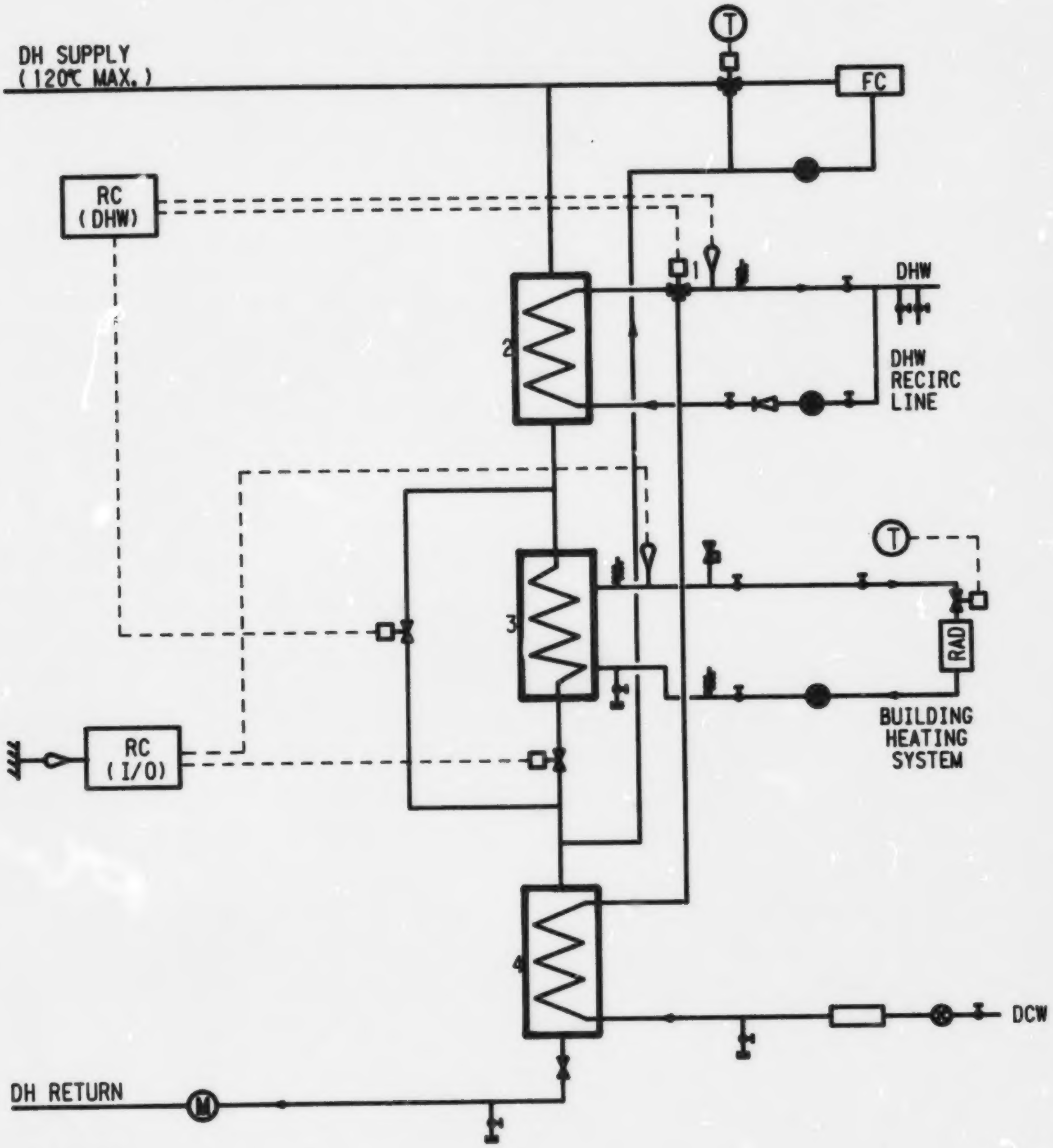

DH SUPPLY
(120°C MAX.)
T
FC
RC
(DHW)
1
DHW
2
DHW
RECIRC
LINE
T
3
RAD
BUILDING
HEATING
SYSTEM
RC
(I/O)
4
DCW
DH RETURN
M

LEGEND

1. TEMPERING VALVE
2. CONVERTOR FOR FINAL HEATING OF DHW.
3. CONVERTOR FOR BUILDING HEATING SYSTEM.
4. CONVERTOR/STORAGE TANK FOR PREHEATING OF DHW.

T	TEMPERATURE CONTROLLER
FC	FAN COIL
RC	REMOTE CONTROLLER (INDOOR/OUTDOOR OR DHW)
RAD	RADIATOR

[100,77]DSS82 .DGN

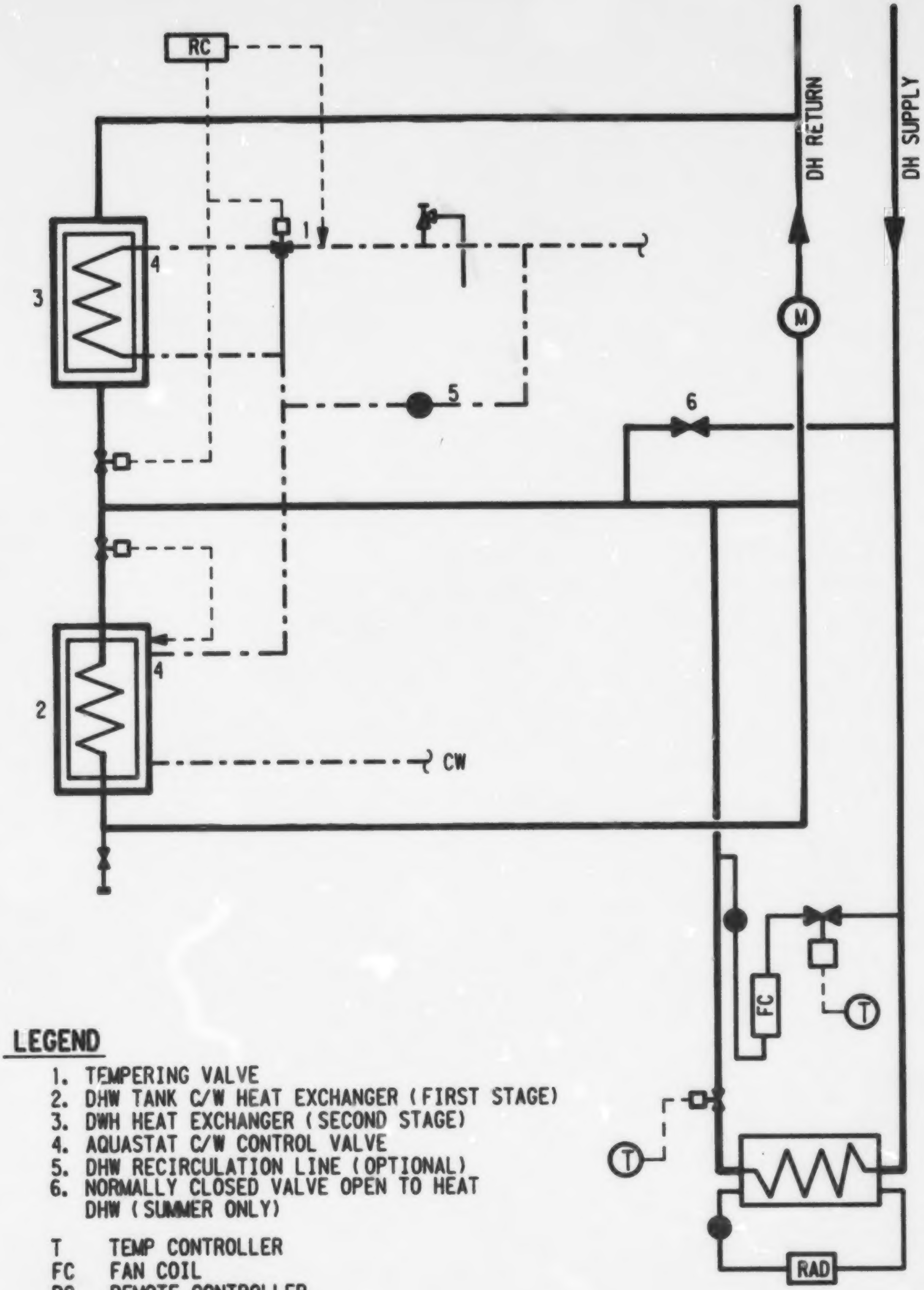
FIGURE 8-2
TYPICAL USER SYSTEMS - LARGE BUILDINGS
3-STAGE CONNECTIONS

approximately the same and the labour costs will also be similar. Therefore, for the purpose of this study, the same costs have been used for both housing types.

The percentage of Canadian urban dwellings equipped with hydronic, forced air and electric systems are of the order of 25, 50 and 20 percent respectively. This applies to existing stock and the share in the new housing stock would be approximately the same. The majority of the electric systems are resistance baseboard type with only about 5 per cent using electric boilers or furnaces.

In common with larger buildings, the cost of connecting existing housing to a DH system is dependent on the existing method of heating. An existing house with a forced air system can be connected to a DH system with little difficulty. The DH water can be connected directly to a heating coil which could be placed in the plenum of the existing furnace (see Figure 8-3). For MTHW, safety concerns would require a locked furnace room. The burner could remain in the furnace as an emergency system. In the case of a hydronic boiler, connection to a DH system would require the installation of a heat exchanger to reduce the temperature of the water entering the building system below 100°C for safety reasons. If the DH water temperature is limited to 90°C, it can pass through the hydronic system directly and no heat exchanger is required, reducing conversion costs.

For a building or house heated with electric baseboards, conversion to district heating would require considerable cutting and patching of partitions, ceilings and floors. This work would be minimized if hydronic rather than a forced air system were installed. Similar to the situation with larger electrically heated buildings it is estimated that such cutting and patching could increase the cost of labour, by 50 per cent relative to installation costs for a new house.



LEGEND

1. TEMPERING VALVE
2. DHW TANK C/W HEAT EXCHANGER (FIRST STAGE)
3. DWH HEAT EXCHANGER (SECOND STAGE)
4. AQUASTAT C/W CONTROL VALVE
5. DHW RECIRCULATION LINE (OPTIONAL)
6. NORMALLY CLOSED VALVE OPEN TO HEAT DHW (SUMMER ONLY)

T	TEMP CONTROLLER
FC	FAN COIL
RC	REMOTE CONTROLLER
RAD	RADIATOR

FIGURE 8-3
PROPOSED SUBSCRIBER SPACE (HYDRONIC OR HOT AIR) AND DHW SYSTEM
SINGLE FAMILY OR DUPLEX

LT00,77JDSS83 .DGN

It was noted in the discussion of DHW systems for offices and apartments that most DHW systems in Europe are of the instantaneous (as required) heater type, while it is common practice in Canada to use storage tanks complete with heat exchangers. It appears that the most attractive option for single family houses in Canada may be a combination of the Canadian/European (storage c/w multiple heat exchangers) practice as shown in Figure 8-3. Low cost glass lined tanks are readily available in Canada and at least two large companies distribute small heat exchangers with the intentions of manufacturing these units in Canada, if the market warrants.

An attractive feature of the storage/heat exchanger concept is that the DH demand load is considerably reduced. Furthermore, the first stage of DHW heating could be heated with the DH water system from the space heating system in a similar manner to the European practice. This would allow DH water to pass through the heat exchanger at a lower temperature and would minimize the effect of scaling on the DHW side of the heat exchanger.

8.3 CONTROL SYSTEMS

The control systems both in the buildings and for the distribution system are very important in a DH system. In general, it is desirable that all control systems in buildings be of a modulating type in order to minimize the effects of water hammer that may occur when solenoid valves close suddenly.

There are several control systems and devices to control the temperature of building space and DHW. The systems for large buildings can be as simple or as elaborate as required, however, the control system design should be compatible with the operating characteristics of the DH system.

While desirable, modulating controls are not commonly used for household systems because the standard low price electric thermostat is not of this type. There are, however, several good, low priced, mechanically operated modulating thermostats, suitable for hydronic systems, that have been developed in Europe and are readily available in Canada.

8.4 METERING DEVICES

The quantity of heat delivered by a hot water DH system depends upon the mass flow and temperature drop between the supply and return. Therefore, in order to measure the heat delivered to the subscriber accurately, it is necessary to measure simultaneously, the supply and return temperatures, and the flow rate to calculate the heat consumed. As a result of the wide spread use of hot water in DH systems in district heating in Europe there has been considerable research and development of heat meters. These meters are capable of accurately recording heat consumption in hot water heating systems over a wide range of temperature and water flow.

These devices electronically integrate flow rate and temperature difference to measure heat consumption. Meters manufactured in Finland are being used successfully in Europe and also on the LeBreton Flats project in Ottawa. The accuracy of these meters improves with higher flow rates and temperature drop, and is typically ±2 per cent.

Unfortunately, these meters are not commercially available in a size and at a cost suitable for domestic use. The lack of low cost small meters is due, in part, to the fact that most of the district heating in Europe is provided to larger buildings and individual apartments have not been metered. It is understood that in Denmark metering of individual dwellings is accomplished with flow meters and water at a constant supply temperature.

The attitude in Europe toward bulk heat metering is changing. Accountability for individual consumption is seen as necessary to promote energy efficiency and conservation. The Dutch are particularly concerned with customer accountability and to this end, the Institute of Physics at Delft has been developing a low cost heat meter. The principle feature of this meter is that the measurement of flow and temperature drop is determined by bleeding off a predetermined amount of water (about one percent). From this water sample, the flow and temperature drop are measured simultaneously and an electronic signal representing the product of the flow and temperature drop is generated and measured as a heat unit. It represents a new concept and if it is successful, it could be manufactured for $100 to $150.

Another metering concept uses a micro-processor to integrate water flow and temperature drop simultaneously. The microprocessor will generate a signal or number which is equivalent to the product of the flow and temperature drop. This in turn represents the heat delivered by the hot water system. This concept is particularly interesting for Canada because there is a high level of Canadian competence in the electronics industry.

8.5 SUBSCRIBER SYSTEM CAPITAL COSTS

The cost of DH subscriber systems are difficult to estimate with the same degree of accuracy as would be expected for traditional building heating systems. The main reasons for this are that heating contractors have had very little experience with such systems and a full range of subscriber equipment is not generally available. However, this situation is improving because European manufacturers have developed large, high performance heat exchangers which are effective in the operation of DH subscriber systems. They manufacture several types of heat exchangers including plate, spiral and others designed to operate at very low approach temperatures. Most of these heat exchangers are available in Canada either as imports or, in some cases, manufactured under agreement with European firms. Small, low cost water/water heat exchangers, suitable for individual houses, are not readily available. However, a large Swedish firm has entered into agreement with a large United States firm to manufacture and market a range of small heat exchangers. These are available in Canada and only recently, one was installed in a laboratory in Ottawa. It is understood that the requirements, and success, of the St. Paul DH project were instrumental in promoting this Swedish/US agreement.

The costs shown in Tables 8-1 to 8-3 inclusive, have been used in this study. They were developed from preliminary designs prepared for office buildings, apartment buildings and houses. Suppliers provided quotations on the various equipment and contractors provided estimates for the installation of the equipment and systems. The cost of systems for office buildings include only those items of equipment which are unique for that particular type of heating system. The costs of the various subscriber systems for apartments are less precise because the options associated with such systems can vary considerably. The costs for detached houses are based on present practice with estimates for variances due to district heating.

This investigation indicates that the cost of subscriber primary heating systems located in the mechanical rooms of office buildings, would be approximately 40% of the cost of conventional systems. For apartment buildings and houses it is estimated that, except for condensing type furnaces, the subscriber costs are roughly the same for all heating options, with electric resistance heating and individual DHW tank being of least cost.

Calculations were performed to relate the subscriber costs to reflect the building heat consumption and three climatological regions. This provides a unit heat cost that can be used in the economic analysis. These costs are presented in Table 8-4.

It is apparent that for most buildings, the cost of subscriber systems suitable for connection to a DH network, will be of the same order as for conventional heating systems. However, the cost of connecting an existing building to a DH network can vary considerably. Such costs, except for the case of steam heating, have been included in Tables 8-1 to 8-3 inclusive.

TABLE 8-1

Single Detached or Duplex Houses
Subscriber System Capital Costs
(Space Heating and DHW)

Item	System	New Installation	Retrofit to connect to DH Network
1	Electric Resistance Base board	$2,000	
2	Retrofit (1) with DH Hydronic System (including cutting and patching)		$3,500
3	Hot Air Gas or Oil Furnace (including ductwork)	2,200	
4	Retrofit (3) for DH System (replace furnace with DH and fan coil unit)		1,150
5	Hydronic System-Gas or Oil Heater(s)	2,200	
6	Retrofit (5) for DH System (replace heaters with DH and heat exchangers)		1,300
7	Condensing Type Furnace (Hot air or hydronic)	4,000	-
8	DH/Fan Coil and Air System	2,500	-
9	DH/Hydronic	2,500	-
10	Flow Meter	150	150

Note: Each item includes DHW system. Individual systems are electric or gas and DH systems (new or retrofit) will use a storage tank with heat exchanger.

All Costs in 1984 dollars.

TABLE 8-2

Apartment Buildings
Subscriber System Capital Costs
(Space Heating and DHW)

Item	System	New Installation	Retrofit to connect to DH Network
1	Electric Resistance Baseboard	$1,700	
2	Retrofit (1) with DH Hydronic System		$3,000
3	Hydronic System (including boilers in Mechanical Room)	2,200	
4	Retrofit (3) for DH System (replace boilers with DH and heat exchangers)		500
5	DH Hydronic System	2,000	
6	Heat Meter for Building and Flow Meter for Each Apartment	150	150

Note: All items - assume a central DHW storage tank and electric heater for item 1 and natural gas heater for item 3 and heat exchanger for items 2, 4 and 5.

TABLE 8-3

Office and Commercial Buildings Subscriber System Capital Costs (Space Heating and DHW)

Item	System	New Installation	Retrofit to connect to DH Network
1	Boiler-Natural Gas Fuel	$46,000	
2	Boiler-#2 Oil	46,000	
3	Boiler-Electric Fuel	78,000	
4	DH Hydronic System	20,000	
5	Retrofit (1 - 3 included) (replace boilers with DH and heat exchangers)		$30,000
6	Heat Meter	1,000	1,000

Note: All items include a central DHW storage tank and heater and use the same heat source for DHW heating as for space heating.

These costs include only the primary heating systems-boilers, heat exchangers and DHW tanks. It is assumed the costs for electric, gas, oil, and DH services and the building HVAC systems are of a similar order of magnitude.

TABLE 8-4

Capital Cost of Subscriber Systems
(1984 $/GJ)

	RESIDENTIAL			APARTMENT			COMMERCIAL		
ITEM	Degree Days			Degree Days			Degree Days		
	3500	4500	5500	3500	4500	5500	3500	4500	5500
1	19	15	13	35	30	27	5.7	4.4	3.6
2	34	28	24	66	56	49	5.7	4.4	3.6
3	21	17	14	46	39	34	9.7	7.5	6.2
4	12	10	9	14	12	10	2.6	2.0	1.7
5	21	17	14	45	38	34	3.8	3.0	2.4
6	14	11	9	-	-	-	-	-	-
7	37	31	26	-	-	-	-	-	-
8	25	20	17	-	-	-	-	-	-
9	25	20	17	-	-	-	-	-	-

Note: See Tables 8-1 to 8-3 for systems related to each item.

Example: Item 6; Residential - 4500 Degree Days

$$\$/GJ = \frac{\text{Equipment Cost + Meter Cost}}{\text{Energy Consumption}}$$

$$= \frac{\$1300 + \$150}{130 \text{ GJ}}$$

$$= 11 \text{ \$/GJ}$$

Conversion of buildings heated by steam, or electric resistance units, will require extensive and costly retrofit work. The only project for which information is available is the St. Paul City Hall. As noted earlier, this heating system was converted from steam to hot water at a reasonable cost.

For the case of apartment and office buildings with hydronic heating, mechanical rooms in the basement and central DHW systems, the retrofit costs will be modest.

Houses which are heated by hot air furnaces could be connected to a DH network at a modest cost. Hydronic heated houses connected to a HTHW system require a water/water heat exchanger which will be more costly than a water/air coil type exchanger. In both cases the DHW heater should be replaced and the cost for the unit is higher than for a conventional system.

Houses with electric resistance baseboard heating will be costly to retrofit due to the cost of the equipment plus significant retrofit work within the house structure.

8.6 OPERATION AND MAINTENANCE

A major advantage of DH subscriber systems is that they have a long life and require relatively little maintenance. Heat exchangers will last indefinitely provided they receive proper maintenance and heating water is suitably treated to minimize scaling, fouling and corrosion. If plate heat exchangers are periodically cleaned, they will not only have a long life, but they will operate efficiently. The traditional shell and tube exchanger also requires little maintenance but it can not operate with the low approach temperatures which are typical of the plate type exchanger.

Fan units and pumps also have a long life span provided they are properly serviced. The maintenance and service of such equipment should be done on a regular basis in order to ensure a long life and minimum operating problems. The life of gas and oil fired furnaces for houses is of the order of 15 to 20 years. Domestic hot water heaters have a life of about 10 - 15 years. The annual maintenance costs of a household furnace or boiler vary considerably depending upon the quality of maintenance provided. It is possible to purchase a prepaid maintenance program in most communities. The cost of maintenance and parts for such programs is about $80 per year. District heating space heat and DHW equipment should have a 30 year life, however the DHW heat exchangers will require periodic maintenance for scaling if the domestic water contains reduce scaling problems to a minor level.

The annual operating and maintenance costs are provided in Table 8-5 and these have been reduced to a cost per heat unit (Table 8-6) in a similar manner to the capital costs.

TABLE 8-5

Subscriber Systems Annual Operating and Maintenance Costs
(1984 $/annum)

	RESIDENTIAL		APARTMENT		COMMERCIAL	
ITEM	New	Retrofit	New	Retrofit	New	Retrofit
1	nil	-	nil	-	3000	-
2	-	30	-	20	3000	-
3	80	-	30	-	3000	-
4	-	30	-	-	1000	-
5	80	-	20	-	-	1000
6	-	30	-	20	-	-
7	80	-	-	-	-	-
8	30	-	-	-	-	-
9	30	-	-	-	-	-

Note: See Tables 8-1 to 8-3 for systems related to each item.

Annual maintenance costs for meters is negligible.

TABLE 8-6

Cost of Operation and Maintenance Per Unit of Heat Delivered (1984 $/GJ)

ITEM	RESIDENTIAL			APARTMENT			COMMERCIAL		
	Degree Days			Degree Days			Degree Days		
	3500	4500	5500	3500	4500	5500	3500	4500	5500
1	nil	nil	nil	nil	nil	nil	.37	.28	.23
2	.28	.23	.20	.42	.36	.31	.37	.28	.23
3	.72	.59	.50	.62	.54	.47	.37	.28	.23
4	.28	.23	.20	.42	.36	.31	.12	.09	.08
5	.72	.59	.50	.42	.36	.31	.12	.09	.08
6	.28	.23	.20	-	-	-	-	-	-
7	.72	.59	.50	-	-	-	-	-	-
8	.28	.23	.20	-	-	-	-	-	-
9	.28	.23	.20	-	-	-	-	-	-

Note: See Tables 8-1 to 8-3 for systems related to each item.

Example: Item 2; Residential - 4500 Degree Days

$$\$1/GJ = \frac{\text{Operating and Maintenance Costs}}{\text{Energy Consumption}}$$

$$= \frac{\$30}{130\ GJ}$$

$$= \$0.23\ \$/GJ$$

PART NINE

ECONOMIC ANALYSIS

PART 9 - ECONOMIC ANALYSIS

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9.1 GENERAL

There are a number of important issues such as technical, economic, environmental, institutional, etc., which have a significant impact on the development of district heating in Canada. Each issue is important and must be carefully analyzed and resolved, however, the economic issues are of particular significance because they affect all aspects of the DH systems including the capital expenditures, operating and maintenance, fuel source and the overall financial arrangements.

Economic feasibility can be demonstrated in several ways. One approach to determining the most economic method of serving an incremental energy load is to compare the long-run marginal costs of alternative methods of meeting that load. This is the approach that is typically used by utility and government planners. Another approach is to examine the long-term costs of meeting the load based not on long-run marginal supply costs but rather long-term expectations of the purchase prices of the alternative energy forms. This approach is more typically used by the consumer in selecting the energy alternative that will most economically meet his heating requirements. This latter approach is often referred to as a commercial feasibility analysis. To the extent that long-term purchase price expectations are different from the expected long-run marginal costs of supply, an economic analysis based on commercial feasibility may identify a different alternative as the preferred option from that which would have been identified using the long-run marginal cost approach.

Purchase prices of conventional energy sources such as oil, natural gas and electricity typically recover the fixed charges associated with the historical investment in existing plant and equipment and the short-run incremental costs of primary energy. In many cases such primary energy costs have been administered costs and are often below the long-run marginal costs of supplying that energy. The pricing of conventional energy supplies on the basis of historical or embedded costs rather than long-run marginal costs of supply may send inappropriate price signals to the consumer, leading to excessive energy consumption and the distortion of market share among differing energy forms. In addition such a pricing policy can represent a significant deterent to the introduction of new energy technologies.

It is beyond the scope of this study to examine the benefits and consequences of various energy pricing approaches. However, for the purposes of this study, the commercial feasibility approach has been used since it more closely reflects the basis upon which the consumer will make his ultimate decisions on heat supply and, consequently, provides a more realistic assessment of the commercial potential for district heating in Canada.

The analysis which follows draws on the technical, climatic, demographic and cost data developed in earlier parts of the report to assess the economic feasibility of district heating. Comparisons of energy alternatives considered in the study are based on the estimated levelized costs of useful heat delivered to the consumer over a thirty year study period. The levelized cost of useful heat is the constant value which if assigned to each unit of useful heat consumed over the study period, results in a present value equal to the present value of the costs incurred to produce it. Levelized costs, expressed in terms of $/GJ, are calculated for the various energy alternatives on the basis of a thirty year study period. Further discussion of the concept of levelized cost is presented in Appendix I.

9.2 ECONOMIC PARAMETERS

921 ESCALATION AND DISCOUNT RATES

Estimates of both capital and operating costs used in the analysis are expressed in terms of constant 1984 dollars and escalation rates are only applied to provide for relative price changes above or below the expected level of general inflation. Based on historic relationships between the rates of change in labour, material and general price levels, it has been assumed, for study purposes, that operation and maintenance costs will increase at a rate of one per cent above the general rate of inflation. The expectations of relative energy price changes used in this study are discussed in Part 923.

Since costs are expressed in constant dollars, a rate of 5 per cent has been used to discount future cash flows. This reflects the estimated historical real cost of capital (i.e. excluding any allowance for general inflation). Sensitivity analyses using 3 per cent and 7 per cent discount rates (the latter being representative of the recent historically high real costs of capital) have also been carried out to examine the impact of changes in the discount rate on the economic feasibility of district heating.

922 SERVICE LIVES

The service life of a component of a heating system is the length of time over which it provides useful service. A long physical life is reasonably possible for any one component of a heating system but factors other than physical deterioration such as technological obsolescence, changes in available energy forms and costs of operation tend to limit the useful life.

It has been assumed for purposes of this study that the normal service life of the typical district heating station, distribution piping system and subscriber system is 30 years and consequently the economic analysis has been based on a 30 year period.

Service lives of conventional alternatives have been assumed to vary from twenty years for a household oil or gas furnace to an indefinite period for an electric baseboard system. Replacements have been assumed to be made at the end of the assumed service life as would be expected in a typical subscriber setting; that is, a furnace would be replaced but ducting would not. For electrical and hydronic systems replacement may include thermostats and little else.

For the case of estimating the costs of existing conventional systems it has been assumed that the present installations of subscriber heating equipment have achieved a steady state with respect to life cycle; that is, new units will replace retired units at a uniform rate. For example, for the case of existing furnaces with an assumed 20 year life, the existing stock would be replaced at the rate of one-twentieth of the total installations or 5 per cent per year and capital costs have been included in the analysis to reflect this assumption. In the case of estimating the costs of new conventional systems which would be required in a greenfield situation, the full cost of the new unit as well as the cost of necessary replacements over the thirty year study period have been included in the analysis. In all cases, credit for any remaining useful life beyond the study period, based on the present value of the expected residual life, has been included in the analysis.

923 ENERGY PRICES

Estimates of the prices of energy, by type and by region, to the end of the study period are required to provide a quantitative framework for the realistic assessment of district heating potential. The principal data source was the Long Term Energy Supply/Demand Outlook Spring '84 Forecast published by the Energy Market Analysis and Statistics Division, Energy Strategy Branch, Energy, Mines and Resources, Canada.

Based on two recent Monenco studies involving energy pricing forecasts, the lower world oil price scenario of the EM&R forecast was accepted for study purposes. This forecast assumes that the Persian Gulf (FOB) price of crude oil will increase at the general rate of inflation from 1984 to 1990. Over the period 1991 to 2000, the price is assumed to increase at one per cent annually in real terms. This assumption was continued beyond the year 2000 to the end of the study period.

The EM&R forecast is based on a set of assumptions that were incorporated directly into the analysis. Specifically, oil prices were calculated on the assumption that current government policies are maintained over the forecast period. This means that the conventional old-oil price is fixed until it achieves the 75 per cent level of the world price. This relationship is continued once the 75 per cent figure has been established. The "Toronto gate" price for natural gas is maintained at a 65 per cent gas/oil parity for the entire study period and "burner tip" prices are developed from this assumption, with appropriate adjustments for transmission costs (or credits) and gas distribution costs. Finally, the forecast assumes that natural gas from the Nova Scotia Shelf - Venture Field will be available in the Atlantic region in 1990. The EM&R forecast provides estimates of the future delivered prices of conventional alternative energy forms for seven regions in Canada. From these data, three energy pricing regimes were used in this study. These different pricing schemes were designated the Atlantic, Central and Western regions.

Atlantic Region prices were taken directly from the EM&R "Atlantic" forecast. The Central Region data was based on the "Ontario" forecast and the Western estimates were based on the "British Columbia, NWT and Yukon" forecast. The actual 1984 energy prices used in the analysis are presented in Part 6 of the report.

Energy prices for residential heat load densities were taken directly from the EM&R "residential" forecast. Prices for intermediate heat load areas were based on an average of residential and commercial rates. Fuels in core heat load densities were priced at the commercial rates appropriate for each region. Fuel prices for the heat stations were taken from the EM&R "industrial" forecast with the exception of prices for coal, wood, peat and municipal solid waste. Coal, wood, peat and municipal solid waste prices were assumed to escalate at the rate assumed by EM&R for coal. All prices, which were expressed in nominal dollars in the EM&R report, were restated to constant 1984 dollars and were also adjusted to reflect the seasonal conversion efficiencies as discussed in Part 6 of the report in order to arrive at the cost of useful heat in $/GJ to the consumer. The real rates of price change implicit in the EM&R forecast are presented in Table 9-1.

924 OPERATION AND MAINTENANCE COSTS

Operation and maintenance costs (excluding fuel or energy costs) for both the conventional and the DH subscriber systems that were developed in Part 8 of the report were used in the economic analysis. For the DH distribution system, non-fuel operation and maintenance costs were assumed to be two per cent of capital costs while, as noted in Part 6, non-fuel operation and maintenance costs

TABLE 9-1

Annual Percent Change in Real Prices

Region/Fuel	Period					
	1984/1985	1985/1986	1986/1987	1987/1990	1990/1995	1995/2000
Atlantic						
Natural Gas:						
Residential	-2.03	-2.48	-2.55	-1.08	-0.09	0.03
Commercial	-2.35	-2.89	-2.60	-1.51	-0.62	-0.42
Industrial	0.22	0.86	0.86	-2.32	0.81	0.69
Light Fuel Oil	-1.54	-1.56	-0.21	0.17	0.65	0.72
Heavy Fuel Oil	-3.73	-2.44	-0.34	0.28	0.70	0.75
Electricity:						
Residential	-2.84	-2.73	-3.01	-2.83	-2.51	1.49
Commercial	-2.81	-2.90	-2.83	-2.94	-2.49	1.48
Industrial	-2.62	-2.93	-3.02	-2.85	-2.50	1.50
Central						
Natural Gas:						
Residential	-1.92	-2.45	-2.51	-0.92	0.14	0.17
Commercial	-1.62	-2.26	-2.32	-0.65	0.39	0.47
Industrial	-2.57	-3.36	-3.23	-0.34	0.82	0.78
Light Fuel Oil	-2.86	-1.93	-0.37	0.21	0.75	0.70
Heavy Fuel Oil	-3.91	-3.56	-1.88	0.20	1.43	1.25
Electricity:						
Residential	2.87	0.00	-0.70	-1.18	-1.30	-1.55
Commercial	2.94	-0.20	-0.61	-1.11	-1.35	-1.55
Industrial	2.73	0.00	-0.38	-1.16	-1.38	-1.48
Western						
Natural Gas:						
Residential	3.64	0.39	2.14	2.59	0.11	0.17
Commercial	4.04	0.65	2.58	2.85	0.27	0.26
Industrial	4.79	1.34	2.92	3.32	0.51	0.45
Light Fuel Oil	-2.50	-1.68	-0.34	0.20	0.68	0.63
Heavy Fuel Oil	-0.33	-1.01	1.29	2.33	1.17	1.06
Electricity:						
Residential	2.78	2.71	2.20	-2.88	-2.94	-1.06
Commercial	2.78	2.70	1.97	-2.88	-2.88	-1.05
Industrial	2.83	2.76	1.92	-2.84	-2.86	-1.16
Other Fuels						
Coal, Wood, Peat MSW	-9.76	-14.05	-1.89	-2.18	2.85	-1.35

Source: Analysis of EM&R Spring 1984 Forecast.

for heat plants ranged from 1.5 to 2.0 per cent of capital costs depending on plant size. In all cases operating and maintenance costs were assumed to escalate at one per cent per annum throughout the study period.

925 OTHER COSTS

Interim replacement, insurance and municipal taxes for heat stations were assumed to be 1.6 per cent of station capital costs. General and administrative costs for the district heating system were estimated to be $1.10/GJ of useful heat in 1984 on the basis of analyses of two electric and two gas distribution utilities in Canada. These costs were also escalated at one per cent per annum over the study period.

Income taxes have not been included in the estimation of district heating costs in this study since the level of taxation, if any, would be dependent on the type of ownership (private or public) and on the capital structure of the enterprise. Private ownership could incur income tax, however, the major portion of any income tax paid to the federal government, under the provisions of the Public Utilities Income Tax Transfer Act, could be subject to rebate to the province of origin and, possibly, ultimately to the DH customers, in certain circumstances.

9.3 ANALYSIS

931 METHODOLOGY

The fundamental objective of the economic analysis is to quantify the potential benefits, if any, that district heating could offer to the Canadian residential and commercial consumer of energy for space and domestic hot water heating purposes, when compared to the costs of competing conventional heat supply systems. The primary analysis examines the potential benefits of converting existing housing stock and commercial buildings to district heating. Sensitivity analyses examine the impact of changes in discount rates and market penetration rates on the economic feasibility. The attractiveness of district heating in serving new heat loads in previously undeveloped areas (greenfield situations) relative to conventional energy alternatives and the economic feasibility of obtaining heat from cogeneration plants have also been examined in the sensitivity analyses. In addition, sensitivity analyses on the rate of change of prices for coal, wood, peat and municipal solid waste fuels have been conducted.

In all cases, a stepped approach has been taken in which the levelized cost of a unit of useful heat (GJ) from a conventional energy source is first determined. This levelized cost includes the capital costs of the subscriber system, the operation and maintenance costs associated with the subscriber heating system and the cost of fuel or energy (oil, natural gas or electricity) over the 30 year study period.

In the second step of the analysis, the levelized cost of installing and operating the subscriber and distribution system (excluding heat plant and fuel costs) of a district heating system required to serve that equivalent heat load (residential, intermediate or core) is developed. This cost is developed on the basis of the estimated distribution system costs set out in Part 7 and the subscriber system costs set out in Part 8 of the report. It is important to note that heat source costs, including the capital costs of the heat plant and fuel costs, are not included in the second step of the analysis.

In the third step, the levelized cost of the DH system (excluding heat source costs) is subtracted from the levelized cost of the conventional heating alternative, derived in step one, to arrive at a levelized "residual value", expressed in $/GJ of useful heat. This "residual value" represents the levelized amount remaining to cover the levelized capital and operating costs, (including fuel), of the heat plant, the transmission system (if required) and also to provide a benefit or saving to the district heating customer, relative to the conventional alternative.

Finally, the levelized cost of producing a unit of useful heat, based on the capital cost and annual operating and maintenance costs, (including fuel), over the thirty year study period, is computed for the range of sizes of heat plants, fuels and fuel prices set out in Part 6 of the report. At the same time, estimated system heat losses of five per cent were included in the determination of the levelized cost of a unit of useful heat.

With this information, and setting aside for the moment the costs of any required transmission facilities, it is possible to determine if district heating is economically attractive for a variety of heat loads (residential, intermediate and core) under a variety of climatic conditions (3500, 4500 and 5500 degree days) when served by heat plants of different sizes using different fuels. These relationships can be determined through interpretation of the calculated data, presented in graphical form.

Figure 9-1 is presented to illustrate the interpretation of the graphical data. The vertical axis of Figure 9-1 shows levelized costs expressed in $/GJ of useful heat. The horizontal axis shows heat plant or cogeneration plant size in MW. Line A represents levelized heat costs and its negative slope demonstrates the economies of scale that are available with increasing heat plant size.

The horizontal Line B represents the residual value in $/GJ of useful heat remaining to cover heat plant capital and operating costs and transmission capital and operating costs. This residual value is the amount remaining after the capital and operating costs of the DH distribution system (excluding heat costs) have been deducted from the levelized costs of owning and operating a conventional heating system. Line B is the estimated levelized residual value that occurs in a 4500 degree day climatic environment. Line B_1 represents the levelized residual value in a 3500 degree day climatic environment. As expected, the levelized residual value available to support the capital and operating cost of the heat plant is lower in the warmer climatic environment. Similarly Line B_2 represents the levelized residual value in a 5500 degree day climatic environment and, with the colder climate, the residual value is greater. It should be noted that the horizontal lines B, B_1 and B_2 are extended across the graph as an aid in relating residual values to heat plant costs and should not be interpreted as suggesting that economies of scale do not apply also to the distribution network. Economies of scale in the distribution network are manifested in the increasing residual values with increasing degree days and increasing heat densities (residential, intermediate, core).

The difference between the residual value (Line B) and the levelized cost of a unit of useful heat (Line A) for any plant size will represent the benefit or savings of district heating in levelized $/GJ. It is clear from the graphical presentation that when Line A rises above Line B, as it does for smaller heat plant sizes, the total

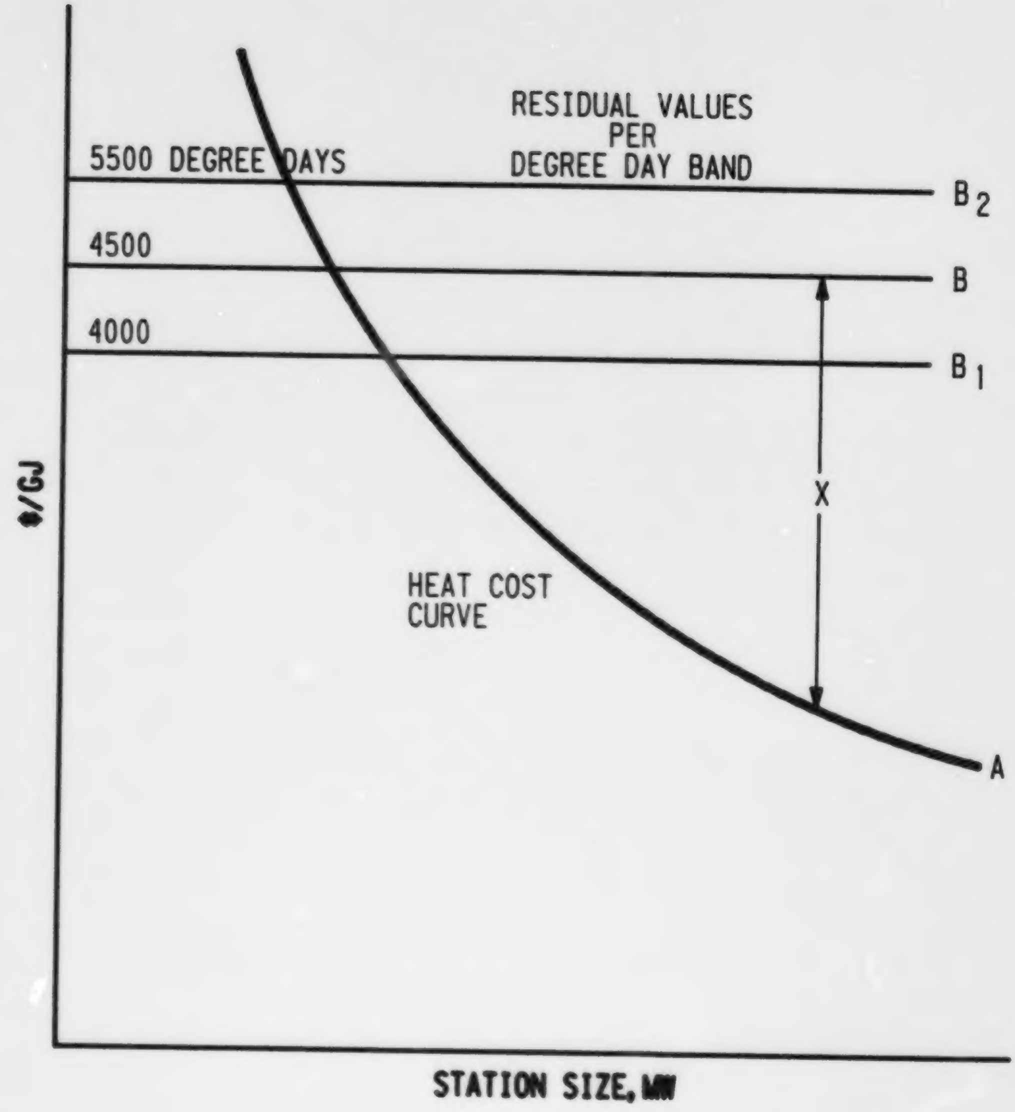

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FIGURE 9-1
LEVELIZED HEAT COST Vs LEVELIZED RESIDUAL VALUE
EXAMPLE

levelized cost of district heating exceeds the levelized cost of the conventional heating system against which it is being compared.

As indicated earlier, the cost of any transmission system required to transport heat, produced at the heat plant, to the distribution network must also be met from the "residual value". Expenditures for transmission piping may be cost effective in transporting heat from a remote location to the load center if thte cost of heat from the heat source is sufficiently low to offset the cost of the transmission system. As discussed in Part 4, such circumstances appear to exist in Edmonton. Transmission requirements, however, are very site specific and consequently can only be dealt with in a general manner in a study of this nature. The estimated capital costs of transmission systems is provided in Part 7 and the annual operation and maintenance costs are assumed to be two percent of the capital costs. Based on the capital costs together with the operation and maintenance costs (escalated at one per cent per annum over the study period), levelized costs of transmission facilities expressed in $/GJ per kilometer have been developed for a variety of plant sizes and two levels of utilization hours. These values are plotted in Figure 9-2. In specific cases where transmission facilities are required, Figure 9-2 provides a basis for estimating the impact of these facilities on district heating costs in a form which is compatible with the other cost calculations in this part of the report.

932 PRIMARY ANALYSIS

As stated previously, the primary analysis considers district heating as a heat source retrofitted to existing housing stock and commercial buildings. Levelized residual values are tabulated for all possible combinations of:

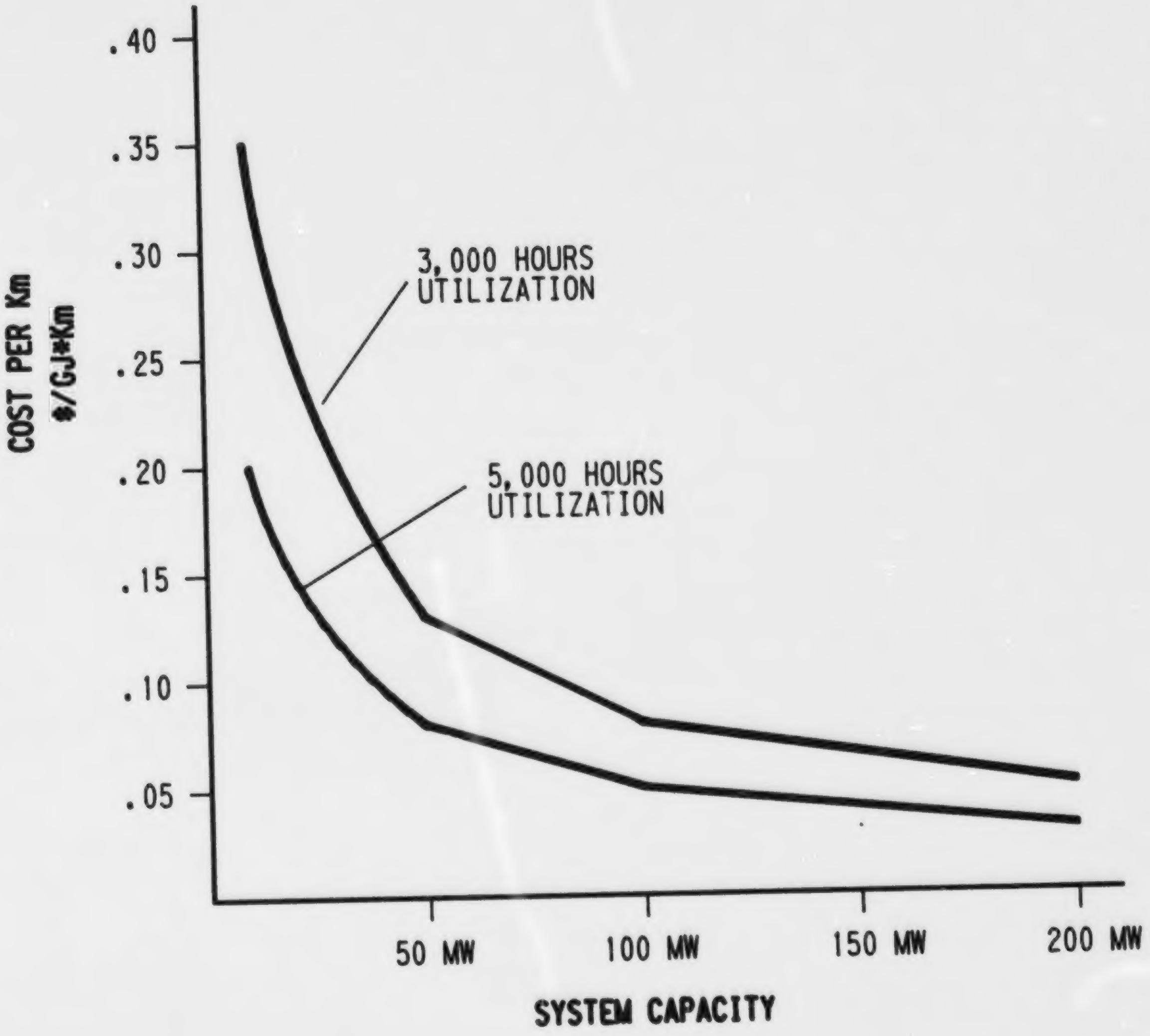

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FIGURE 9-2
TRANSMISSION SYSTEM COSTS
LEVELIZED @ 5%

(i) Three heat load densities:
- residential heat loads
- intermediate heat loads
- core heat loads

(ii) Three climatic regimes:
- 3500 degree days
- 4500 degree days
- 5500 degree days

(iii) Three energy pricing regimes:
- Atlantic Canada
- Central Canada
- Western Canada

(iv) Six heating alternatives for residential heat loads:
- electric baseboard
- natural gas hot air
- natural gas hydronic baseboard
- natural gas condensing furnace
- light fuel oil hot air
- light fuel oil hydronic baseboard

(v) Five heating alternatives for intermediate heat loads:
- electric baseboard
- natural gas hot air
- natural gas hydronic
- light fuel oil hot air
- light fuel oil hydronic

(vi) Three heating alternatives for core heat loads:
- natural gas boiler
- light fuel oil boiler
- electric boiler

These combinations result in a total of 54 residential heat load cases, 45 intermediate heat load cases and 27 core heat load cases. Table 9-2 presents the levelized costs of all conventional heat sources for the full range of heat load densities, geographic price regimes and climate conditions. The levelized residual values for residential heat load densities are presented in Table 9-3. Levelized residual values for intermediate and core heat load densities are presented in Tables 9-4 and 9-5 respectively.

In order to determine the levelized cost of supplying heat to the DH system the following combinations of plant size, fuel types and pricing regimes are examined:

(i) Three energy pricing regimes:
- Atlantic Canada
- Central Canada
- Western Region

(ii) Four plant sizes:
- 18 MW
- 150 MW
- 300 MW
- 1500 MW

(iii) Six fuel types:
- natural gas
- heavy oil
- coal
- wood-biomass (18,150 and 300 MW sizes only)
- peat (18,150 and 300 MW sizes only)
- municipal solid waste (18 and 150 MW sizes only)

TABLE 9-2

Conventional Heating System
Levelized Total Subscriber Costs
Levelized @ 5%

Heating System by Density	Degree Days by Region								
	Atlantic			Central			Western		
	3500	4500	5500	3500	4500	5500	3500	4500	5500
	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)
Residential									
Electric Base Board	12.78	12.76	12.74	10.81	10.79	10.77	10.96	10.94	10.92
NGas Hot Air	13.01	12.72	12.52	11.41	11.12	10.91	11.00	10.71	10.50
NGas Hydronic	12.23	12.07	11.96	10.62	10.47	10.36	10.21	10.06	9.95
NGas Condensing	9.63	9.37	9.10	8.70	8.30	8.03	8.42	8.03	7.76
LFO Hot Air	16.31	16.02	15.81	15.13	14.83	14.63	16.06	15.72	15.56
LFO Hydronic	15.52	15.37	15.26	14.34	14.18	14.08	15.27	15.12	15.01
Intermediate									
Electric Base Board	14.58	14.55	14.53	11.60	11.57	11.55	11.02	10.99	10.97
NGas Hot Air	13.15	12.96	12.81	10.00	9.80	9.66	10.13	9.93	9.78
NGas Hydronic	12.80	12.75	12.69	9.65	9.60	9.53	9.78	9.73	9.66
LFO Hot Air	15.81	15.61	15.46	14.62	14.43	14.28	15.50	15.36	15.21
LFO Hydronic	15.46	15.41	15.34	14.28	14.22	14.16	15.21	15.16	15.09
Core									
NGas Boiler	13.25	13.11	13.02	8.55	8.40	8.32	9.21	9.07	8.99
LFO Boiler	15.27	15.12	15.04	14.08	13.94	13.86	15.01	14.82	14.76
Electric Boiler	16.75	16.61	16.52	12.77	12.63	12.55	11.45	11.31	11.23

TABLE 9-3

Residential Retrofit
Levelized Residual Value*
Levelized @ 5%

Region	Electric Base Board	Natural Gas		Natural Gas Condensing	Light Fuel Oil	
		Hot Air	Hydronic BB		Hot Air	Hydronic BB
	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)
Atlantic						
3500 DD	4.83	6.49	5.51	2.92	9.78	8.81
4500 DD	6.25	7.38	6.61	3.91	10.68	9.91
5500 DD	7.02	7.78	7.17	4.30	11.08	10.46
Central						
3500 DD	2.85	4.88	3.91	1.98	8.60	7.62
4500 DD	4.27	5.78	5.01	2.84	9.50	8.72
5500 DD	5.04	6.18	5.56	3.23	9.90	9.28
Western						
3500 DD	3.01	4.47	3.50	1.71	9.53	8.56
4500 DD	4.43	5.37	4.60	2.57	10.39	9.66
5500 DD	5.20	5.77	5.15	2.96	10.83	10.21

---

* Levelized unit cost of conventional heating system less levelized unit cost of DH subscriber system and distribution network required to serve the equivalent heat load density, excluding heat plant and fuel costs. For example looking at Table 9-2, the levelized cost of useful heat from a residential electric base board system in a 3500 degree day climate and an Atlantic pricing regime is $12.78. When the levelized cost of the DH subscriber system and distribution network required to serve the equivalent heat load, an amount of $7.95, is subtracted, a residual amount of $4.83 remains to cover the cost of heat production.

TABLE 9-4

Intermediate Retrofit
Levelized Residual Value*
Levelized @ 5%

Region	Electric Base Board	Natural Gas		Light Fuel Oil	
		Hot Air	Hydronic	Hot Air	Hydronic
	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)
Atlantic					
3500 DD	8.04	8.41	8.06	11.06	10.72
4500 DD	8.87	8.82	8.62	11.48	11.27
5500 DD	9.46	9.00	8.88	11.66	11.53
Central					
3500 DD	5.06	5.26	4.91	9.88	9.53
4500 DD	5.89	5.67	5.47	10.29	10.09
5500 DD	6.48	5.85	5.74	10.47	10.35
Western					
3500 DD	4.48	5.38	5.04	10.76	10.47
4500 DD	5.31	5.80	5.59	11.23	11.02
5500 DD	5.90	5.98	5.86	11.41	11.28

* Levelized unit cost of conventional heating system less levelized unit cost of DH subscriber system and distribution network required to serve the equivalent heat load density excluding heat plant and fuel costs.

TABLE 9-5

Core Retrofit
Levelized Residual Value*
Levelized @ 5%

Region	Natural Gas Boiler	Light Fuel Oil Boiler	Electric Boiler
	($/GJ)	($/GJ)	($/GJ)
Atlantic			
3500 DD	11.13	13.15	14.63
4500 DD	11.14	13.16	14.64
5500 DD	11.18	13.20	14.68
Central			
3500 DD	6.43	11.96	10.65
4500 DD	6.44	11.97	10.66
5500 DD	6.48	12.01	10.70
Western			
3500 DD	7.10	12.90	9.33
4500 DD	7.11	12.91	9.35
5500 DD	7.15	12.95	9.38

* Levelized unit cost of conventional heating system less levelized unit cost of DH subscriber system and distribution network required to serve the equivalent heat load density excluding heat plant and fuel costs.

These combinations result in a total of 60 levelized heat station costs. Levelized heat station costs for the Atlantic, Central and Western price regimes are presented in Tables 9-6, 9-7, and 9-8 respectively.

Theoretically at least, the possible combination of 42 residual values with 20 heat station costs in each of three price regimes could have led to a total of 2520 cases in the primary analysis.

In order to confine the analysis to manageable proportions it was decided to evaluate district heating against the most economical conventional heating alternatives. The most economical conventional alternatives are identified as the alternatives having the lowest levelized cost of a unit of useful heat. Table 9-2 shows that the natural gas condensing furnace is the least cost residential alternative, the natural gas hydronic baseboard the least cost intermediate alternative and the natural gas boiler the least cost alternative in core heat density areas. However, natural gas is generally unavailable in Atlantic Canada and there is limited distribution of natural gas condensing furnaces. Consequently, all gas fueled alternatives in Atlantic Canada and all condensing gas furnace alternatives were eliminated from further consideration in the retrofit analysis. On the heat plant side, it was considered that the 1500 MW plant, which could theoretically supply about 125,000 houses, was unrealistic for Canada at this time and was excluded from further analysis. The following cases were identified as the alternatives against which district heating would be evaluated.

Heat Load Density	Least Cost Conventional Heat Source		
	Atlantic	Central	Western
Residential	Electric Baseboard	Natural Gas Hydronic Baseboard	Natural Gas Hydronic Baseboard
Intermediate	Electric Baseboard	Natural Gas Hydronic Baseboard	Natural Gas Hydronic Baseboard
Core	Light Fuel Oil Boiler	Natural Gas Boiler	Natural Gas Boiler

TABLE 9-6

Atlantic Region
Levelized Heat Station Costs
Levelized @ 5%

Station Size	FUEL TYPE					
	Gas	Oil	Coal	Wood-Biomass	Peat	MSW
	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)
18 MW	8.39	9.17	9.59	13.19	13.86	12.53
150 MW	6.91	7.48	6.50	8.30	8.67	7.89
300 MW	6.81	7.36	5.18	6.17	6.45	N/A
1500 MW	6.59	7.13	4.34	N/A	N/A	N/A

TABLE 9-7

Central Region
Levelized Heat Station Costs
Levelized @ 5%

Station Size	FUEL TYPE					
	Gas	Oil	Coal	Wood-Biomass	Peat	MSW
	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)
18 MW	7.75	7.46	9.52	13.11	13.80	12.45
150 MW	6.31	5.88	6.43	8.22	8.59	7.81
300 MW	6.20	5.77	5.11	6.09	6.45	N/A
1500 MW	5.98	5.53	4.27	N/A	N/A	N/A

TABLE 9-8

Western Region
Levelized Unit Heat Station Unit Costs
Levelized @ 5%

Station Size	FUEL TYPE Gas	 Oil	 Coal	 Wood-Biomass	 Peat	 MSW
	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)
18 MW	7.93	7.68	9.52	13.10	13.80	12.45
150 MW	6.48	6.14	6.43	8.21	8.58	7.81
300 MW	6.38	5.97	5.11	6.08	6.36	N/A
1500 MW	6.17	5.73	4.26	N/A	N/A	N/A

The levelized residual values based on these least cost conventional alternatives have been plotted against the levelized heat plant costs in a manner similar to that shown in Figure 9-1. Figures 9-3, 9-4 and 9-5 show the results for the Atlantic, Central and Western regions respectively. Due to overlapping of residual value lines in the Central and Western Regions, residential, intermediate and core heat load densities are plotted on separate graphs in Figures 9-4 and 9-5. As discussed previously, the greater the difference between the levelized residual value (the horizontal lines on the graphs) and the levelized heat plant costs (the negatively sloping lines on the graphs) the greater the economic benefits of district heating.

Referring to Figure 9-3, it can be seen that the economics of district heating improve as the heat load density increases due either to climatological factors (increasing degree days) or load types (residential, intermediate, core) and also with absolute load size as indicated by plant size. It is clear from Figure 9-3 that in the Atlantic region district heating offers economic benefits to core heat loads but is of limited interest for intermediate and residential heat loads unless they can be served by larger plants. The same general relationships are evident in Figures 9-4 and 9-5 for the Central and Western regions; however, the availability of natural gas in these regions dramatically reduces the attractiveness of district heating even for the core areas, with significant benefits available only for heat loads that can be served by large plant sizes.

While Figures 9-3, 9-4 and 9-5 indicate if district heating offers any savings over conventional heating alternatives, these graphical presentations, based on residual values rather than total costs, do not indicate percentage savings over conventional heating alternatives. This information is provided in Tables 9-9, 9-10 and 9-11 for the Atlantic, Central and Western regions respectively.

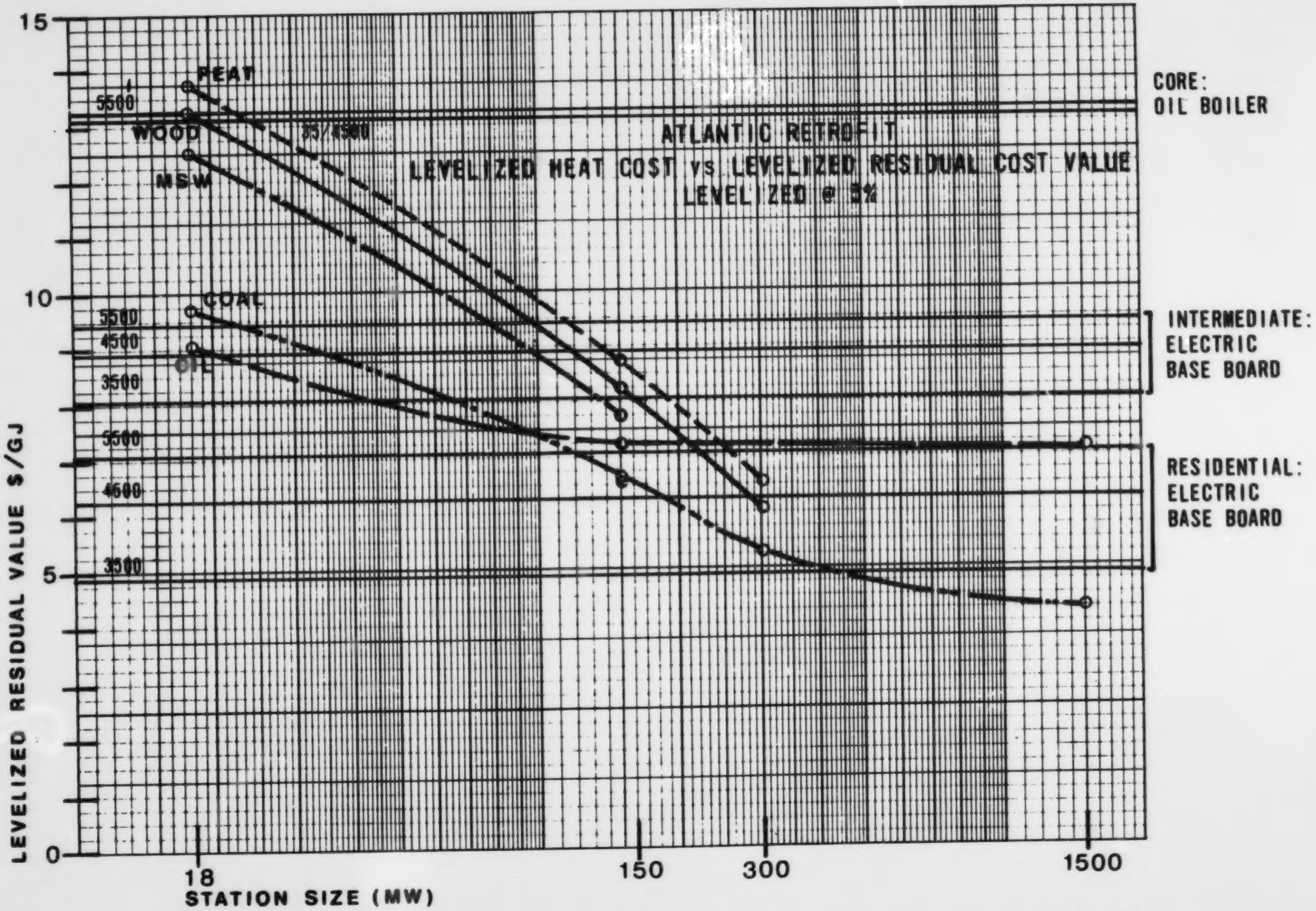
ATLANTIC RETROFIT
LEVELIZED HEAT COST vs LEVELIZED RESIDUAL COST VALUE
LEVELIZED @ 3%
PEAT
WOOD
MSW
COAL
OIL
35/4500
5500
5500
4500
3500
5500
4500
3500
CORE:
OIL BOILER
INTERMEDIATE:
ELECTRIC
BASE BOARD
RESIDENTIAL:
ELECTRIC
BASE BOARD
LEVELIZED RESIDUAL VALUE $/GJ
15
10
5
0
18
150
300
1500
STATION SIZE (MW)

FIGURE 9-3

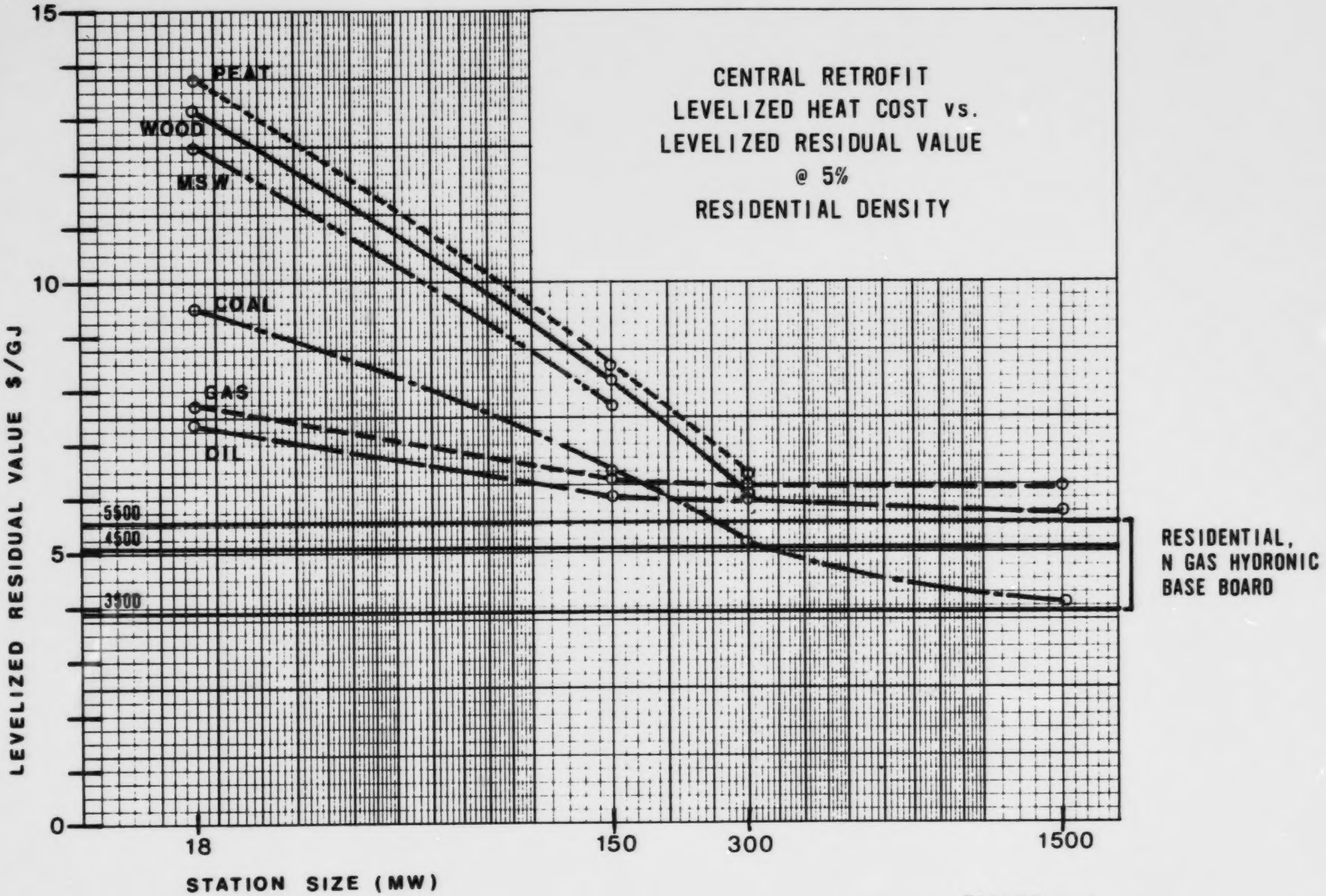
CENTRAL RETROFIT
LEVELIZED HEAT COST vs.
LEVELIZED RESIDUAL VALUE
@ 5%
RESIDENTIAL DENSITY
PEAT
WOOD
MSW
COAL
GAS
OIL
5500
4500
3500
RESIDENTIAL,
N GAS HYDRONIC
BASE BOARD
LEVELIZED RESIDUAL VALUE $/GJ
15
10
5
0
18
150
300
1500
STATION SIZE (MW)

FIGURE 9-41

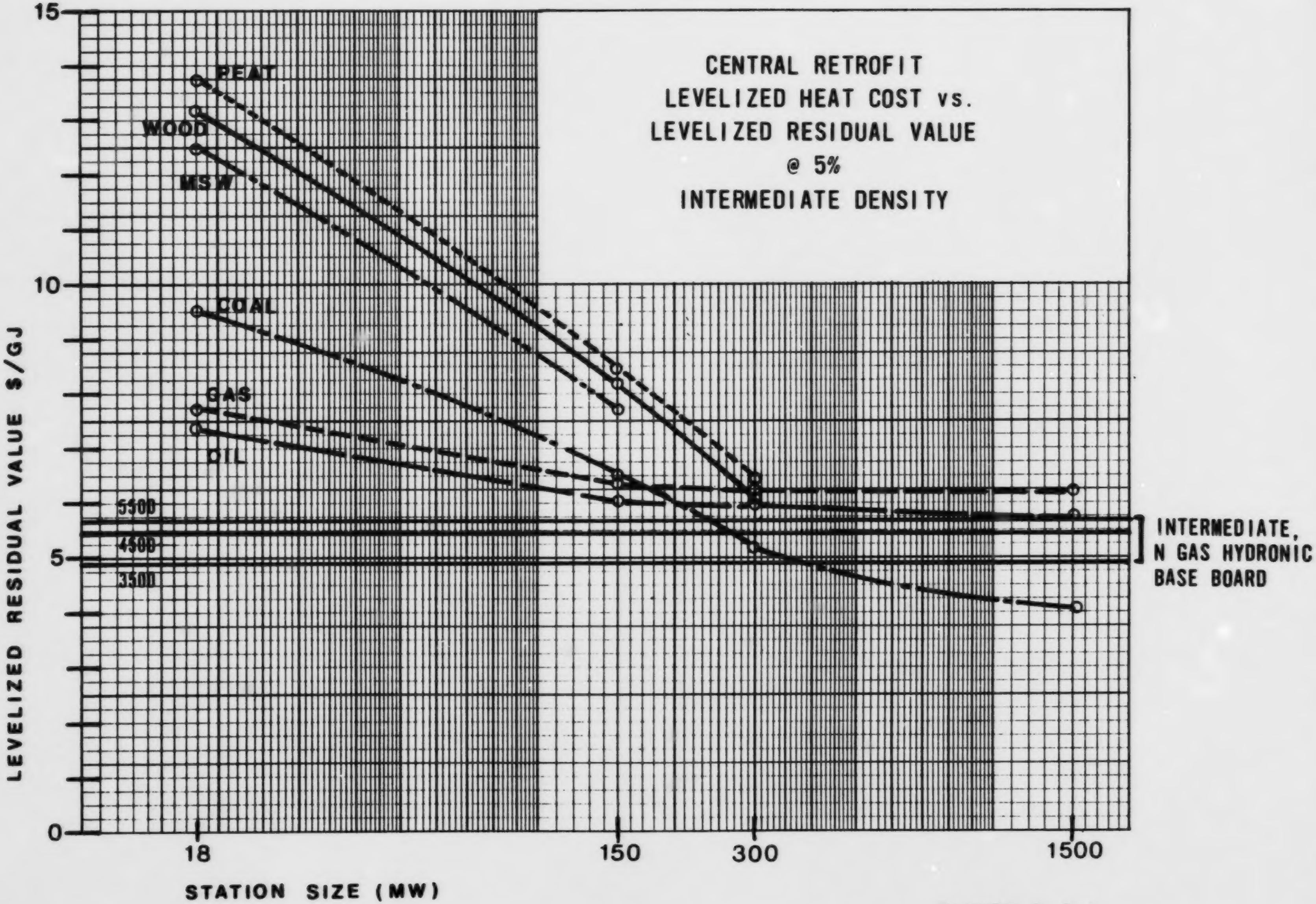CENTRAL RETROFIT
LEVELIZED HEAT COST vs.
LEVELIZED RESIDUAL VALUE
@ 5%
INTERMEDIATE DENSITY
PEAT
WOOD
MSW
COAL
GAS
OIL
5500
4500
3500
INTERMEDIATE,
N GAS HYDRONIC
BASE BOARD
LEVELIZED RESIDUAL VALUE $/GJ
15
10
5
0
18
150
300
1500
STATION SIZE (MW)

FIGURE 9-4ii

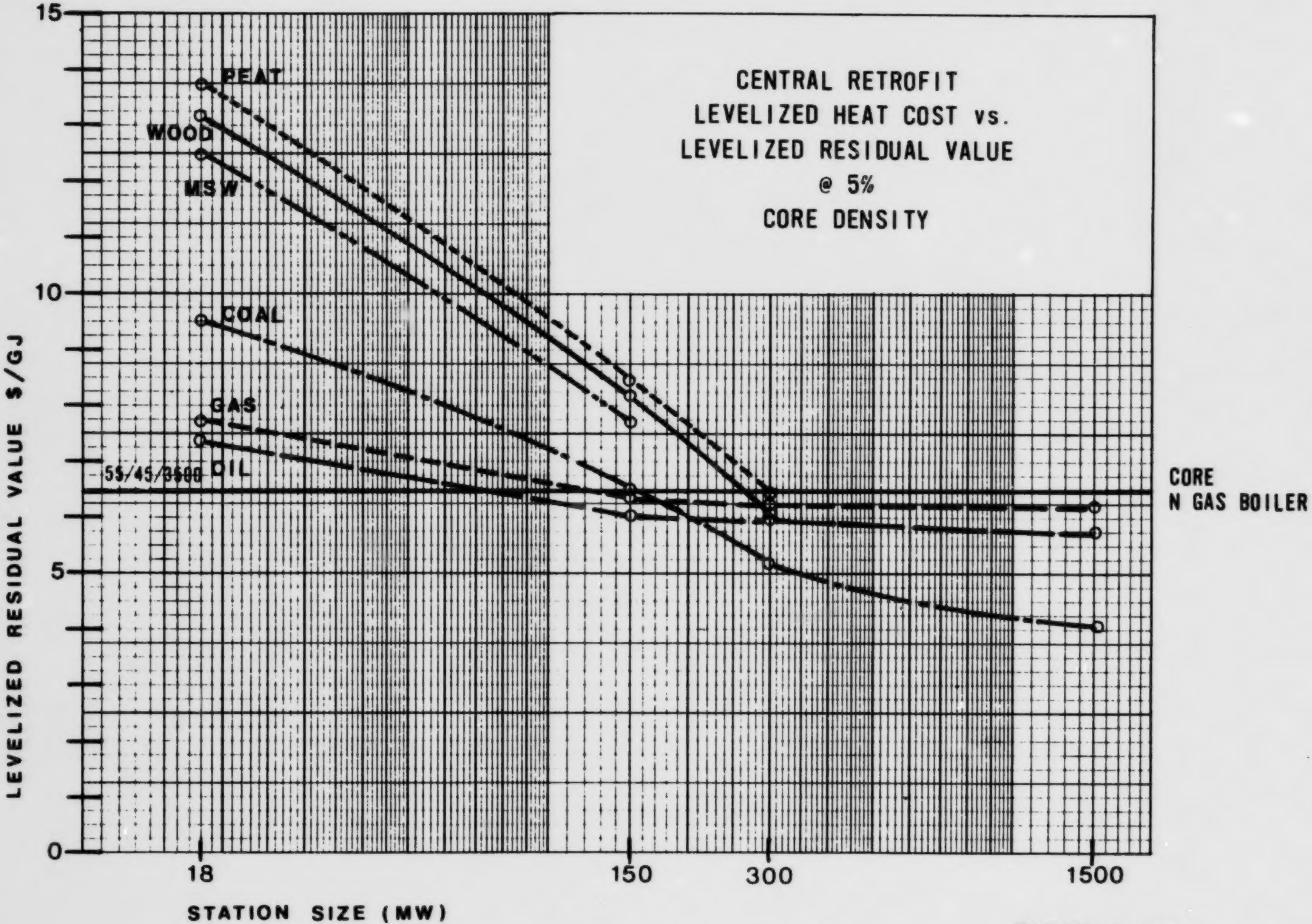

FIGURE 9-4iii

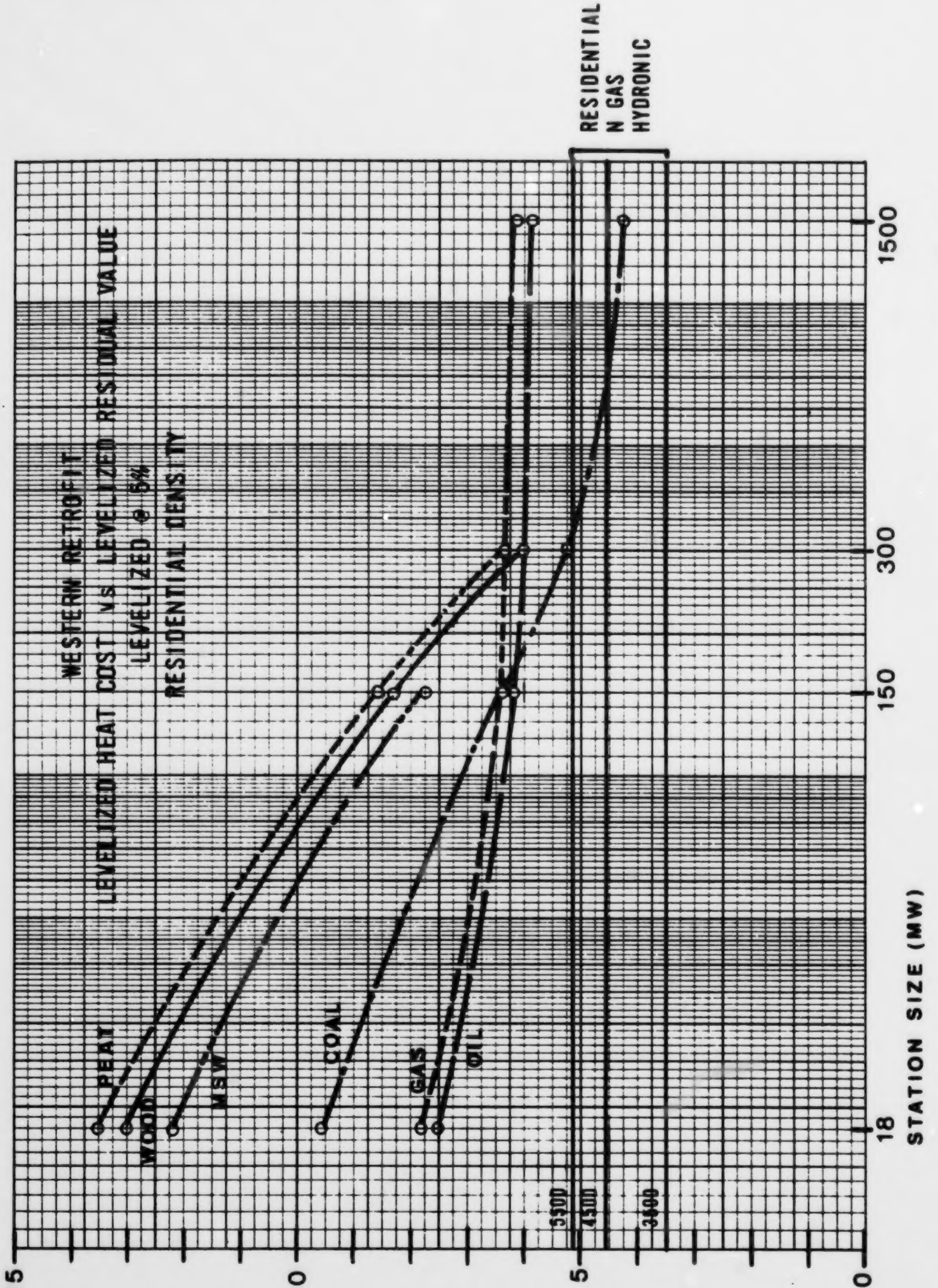
WESTERN RETROFIT
LEVELIZED HEAT COST VS LEVELIZED RESIDUAL VALUE
LEVELIZED @ 5%
RESIDENTIAL DENSITY
PEAT
WOOD
MSW
COAL
GAS
OIL
RESIDENTIAL
N GAS
HYDRONIC
5500
4500
3500
15
10
5
0
18
150
300
1500
STATION SIZE (MW)
LEVELIZED RESIDUAL VALUE $/GJ

FIGURE 9-51

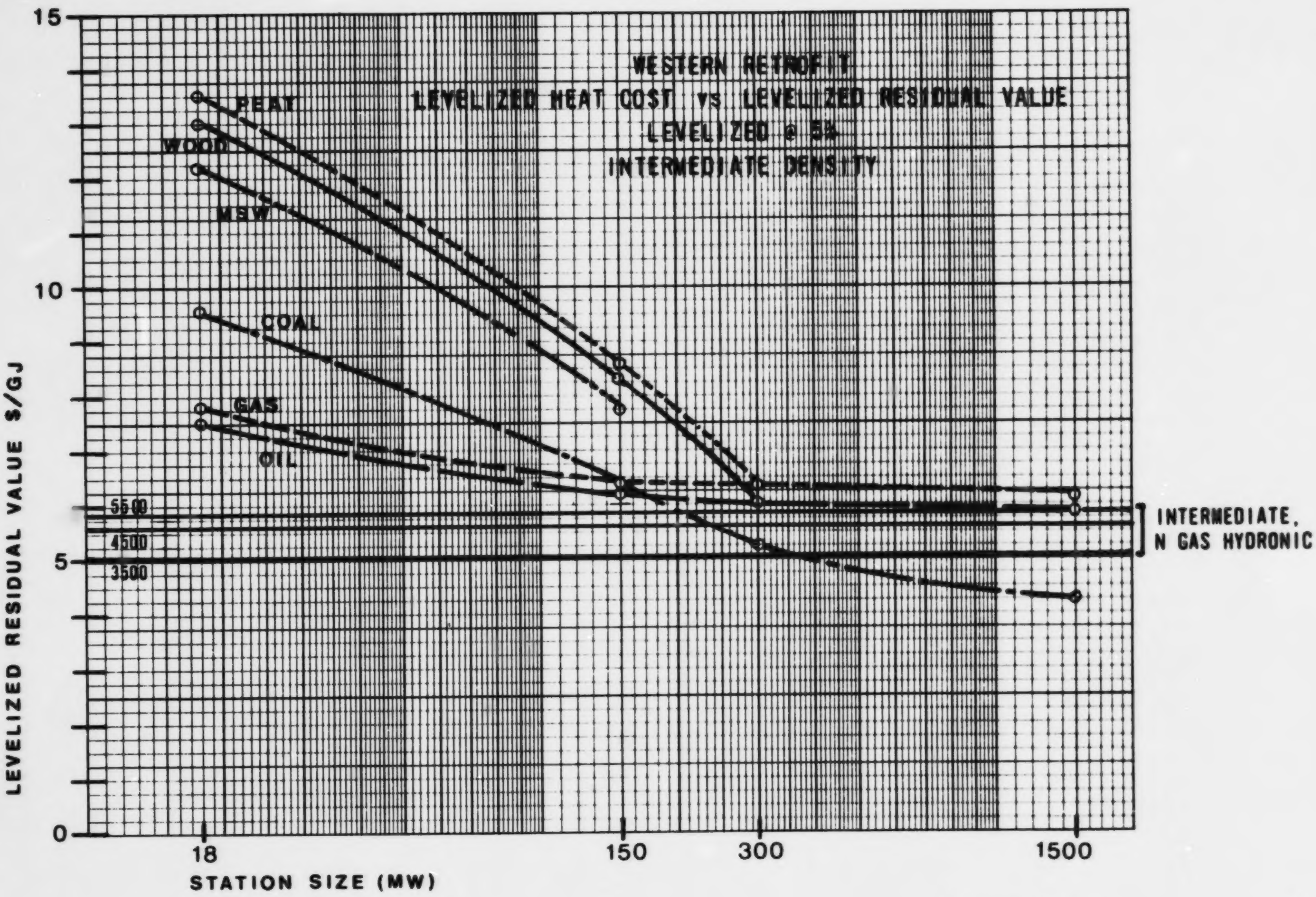
WESTERN RETROFIT
LEVELIZED HEAT COST vs LEVELIZED RESIDUAL VALUE
LEVELIZED @ 5%
INTERMEDIATE DENSITY
PEAT
WOOD
MSW
COAL
GAS
OIL
5500
4500
3500
INTERMEDIATE,
N GAS HYDRONIC
15
10
5
0
LEVELIZED RESIDUAL VALUE $/GJ
18
150
300
1500
STATION SIZE (MW)

FIGURE 9-511

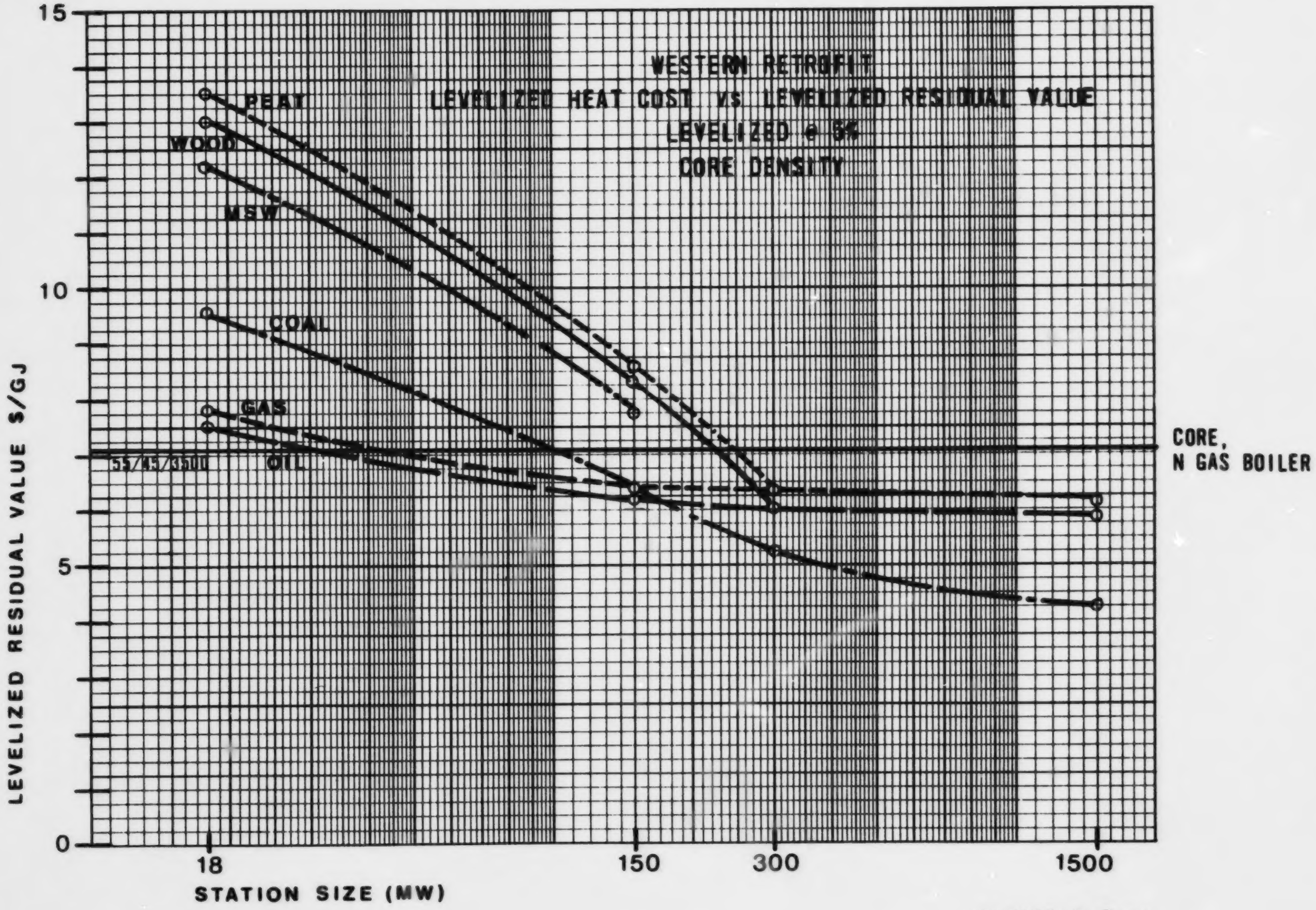

FIGURE 9-5III

TABLE 9-9

Atlantic Retrofit
Benefit Analysis @ 5%
Percentage Benefit: D.H. vs Conventional Heating System

Density @ 4500 DD	Station Size		
	18 MW	150 MW	300 MW
	(%)	(%)	(%)
Core (LFO Boiler)			
Minimum	4 (MSW)	30 (Peat)	38 (Oil)
Maximum	26 (Oil)	44 (Coal)	53 (Coal)
Intermediate (Electric Baseboard)			
Minimum	-	4 (Wood)	10 (Oil)
Maximum	-	16 (Coal)	25 (Coal)
Residential (Electric Baseboard)			
Minimum	-	-	1 (Wood)
Maximum	-	-	8 (Coal)

TABLE 9-10

Central Retrofit
Benefit Analysis @ 5%
Percentage Benefit: D.H. vs Conventional Heating System

	Station Size		
Density @ 4500 DD	18 MW	150 MW	300 MW
	(%)	(%)	(%)
Core (Natural Gas Boiler)			
Minimum	-	-	4 (Wood)
Maximum	-	17 (Oil)	16 (Coal)
Intermediate (Natural Gas Hydronic Baseboard)			
Minimum	-	-	-
Maximum	-	-	4 (Coal)
Residential (Natural Gas Hydronic Baseboard)			
Minimum	-	-	-
Maximum	-	-	-

TABLE 9-11

Western Retrofit
Benefit Analysis @ 5%
Percentage Benefit: D.H. vs Conventional Heating System

Density @ 4500 DD	Station Size 18 MW (%)	 150 MW (%)	 300 MW (%)
Core (Natural Gas Boiler)			
Minimum	–	8 (Coal)	8 (Peat)
Maximum	–	11 (Oil)	22 (Coal)
Intermediate (Natural Gas Hydronic Baseboard)			
Minimum	–	–	–
Maximum	–	–	5 (Coal)
Residential (Natural Gas Hydronic Baseboard)			
Minimum	–	–	–
Maximum	–	–	–

These tables show the percentage differences between the total levelized cost of the least cost conventional heating alternative and the total levelized cost of district heating including subscriber system, distribution system and heat plant costs for various plant sizes and fuels. Where positive benefits exist, both the minimum benefit and maximum benefit in percentage terms are indicated.

These results indicate that district heating is most attractive in areas with relatively high cost conventional heating alternatives and high heat load densities. In addition, larger station sizes where economies of scale are greatest, significantly improve the attractiveness of district heating.

933 SENSITIVITY ANALYSIS

In order to assess the impact of changes in major study assumptions on the results of the economic analysis a number of sensitivity analyses have been carried out on the following study variables:

(i) market penetration
(ii) discount rates
(iii) greenfield installation capital costs
(iv) use of cogeneration rather than heat only plants
(v) rate of price change for coal, wood, peat and municipal solid waste.

The results of these analyses are presented below:

.1 Market Penetration

The primary economic analysis is based on the levelized costs of district heating assuming that all heat consumers within a district heating service area would connect to the DH system (100 per cent market penetration). In the absence of mandatory connection requirements this may not be a realistic assumption. In order to examine the impact of reduced market penetration on the economic viability of district heating, sensitivity analyses have been carried out in which it has been assumed that only 50 per cent of the potential heating load within the DH system service area is connected to the DH system.

As discussed in Part 7, a reduction in market penetration can significantly increase the unit capital costs of the DH distribution system particularly for low density heat loads. This is due to the fact that the DH mains are designed and built to serve the total heat load while the cost per heat unit delivered depends upon market penetration. In addition, the reduced market penetration results in a smaller total heat load and therefore a smaller heat station and the potential loss of signficant economies of scale in heat production.

Levelized residual values based on the least cost conventional alternatives, discussed in Part 932 and at 50 per cent district heating market penetration are presented in Tables 9-12, 9-13 and 9-14 for the Atlantic, Central and Western regions respectively. These residual values have been plotted against levelized heat plant costs in Figure 9-6 for the Atlantic Region, Figure 9-7 for the Central Region and 9-8 for the Western Region. Again, due to overlapping of residual value lines in the Central and Western Regions, residential, intermediate and core heat load densities are plotted on separate graphs in Figures 9-7 and 9-8.

The residual values with 50 per cent market penetration, expressed as a percentage of residual values with 100 per cent market penetration are presented in Table 9-15. The residual values for the residential areas show the greatest decrease as a result of the reduction in market penetration thus, reflecting the sensitivity of DH network unit capital costs to heat density.

TABLE 9-12

Residential Retrofit
Levelized Residual Value*
Market Penetration @ 50%
Levelized @ 5%

Region	Electric Base Board	Natural Gas Hot Air	Natural Gas Hydronic BB	Natural Gas Condensing	Light Fuel Oil Hot Air	Light Fuel Oil Hydronic BB
	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)
Atlantic						
3500 DD	1.54	3.20	2.22	-0.37	6.49	5.52
4500 DD	4.06	5.19	4.42	1.71	8.49	7.72
5500 DD	5.58	6.35	5.73	2.87	9.65	9.03
Central						
3500 DD	-0.31	1.59	0.62	-1.31	5.31	4.34
4500 DD	2.08	3.59	2.82	0.65	7.30	6.53
5500 DD	3.61	4.75	4.13	1.80	8.46	7.85
Western						
3500 DD	-0.28	1.18	0.21	-1.58	6.24	5.27
4500 DD	2.24	3.18	2.41	0.38	8.20	7.47
5500 DD	3.76	4.34	3.72	1.53	9.40	8.78

---

* Levelized unit cost of conventional heating system less levelized unit cost of DH subscriber system and distribution network required to serve the equivalent heat load density excluding heat plant and fuel costs. Negative residual values indicate that the levelized cost of the DH subscriber system and network, excluding heat plant and fuel costs, exceed the levelized cost of the conventional system.

TABLE 9-13

Intermediate Retrofit
Levelized Residual Value*
Market Penetration @ 50%
Levelized @ 5%

Region	Electric	Natural Gas		Light Fuel Oil	
	Base Board	Hot Air	Hydronic BB	Hot Air	Hydronic BB
	($/GJ)	($/GJ)	($/GJ)	($/GJ)	($/GJ)
Atlantic					
3500 DD	6.27	6.64	6.29	9.29	8.94
4500 DD	7.81	7.77	7.56	10.42	10.22
5500 DD	9.04	8.58	8.46	11.24	11.11
Central					
3500 DD	3.29	3.48	3.14	8.11	7.76
4500 DD	4.84	4.61	4.41	9.24	9.03
5500 DD	6.06	5.43	5.31	10.05	9.93
Western					
3500 DD	2.71	3.61	3.27	8.99	8.69
4500 DD	4.26	4.74	4.54	10.17	9.97
5500 DD	5.48	5.56	5.44	11.02	10.86

---

* Levelized unit cost of conventional heating system less levelized unit cost of DH subscriber system and distribution network required to serve the equivalent heat load density excluding heat plant and fuel costs.

TABLE 9-14

Core Retrofit
Levelized Residual Value*
Market Penetration @ 50%
Levelized @ 5%

Region	Natural Gas Boiler	Light Fuel Oil Boiler	Electric Boiler
	($/GJ)	($/GJ)	($/GJ)
Atlantic			
3500 DD	10.68	12.69	14.18
4500 DD	10.66	12.68	14.16
5500 DD	10.67	12.68	14.17
Central			
3500 DD	5.97	11.51	10.20
4500 DD	5.96	11.49	10.18
5500 DD	5.96	11.50	10.19
Western			
3500 DD	6.64	12.48	8.88
4500 DD	6.63	12.43	8.87
5500 DD	6.63	12.45	8.87

* Levelized unit cost of conventional heating system less levelized unit cost of DH subscriber system and distribution network required to serve the equivalent heat load density excluding heat plant and fuel costs.

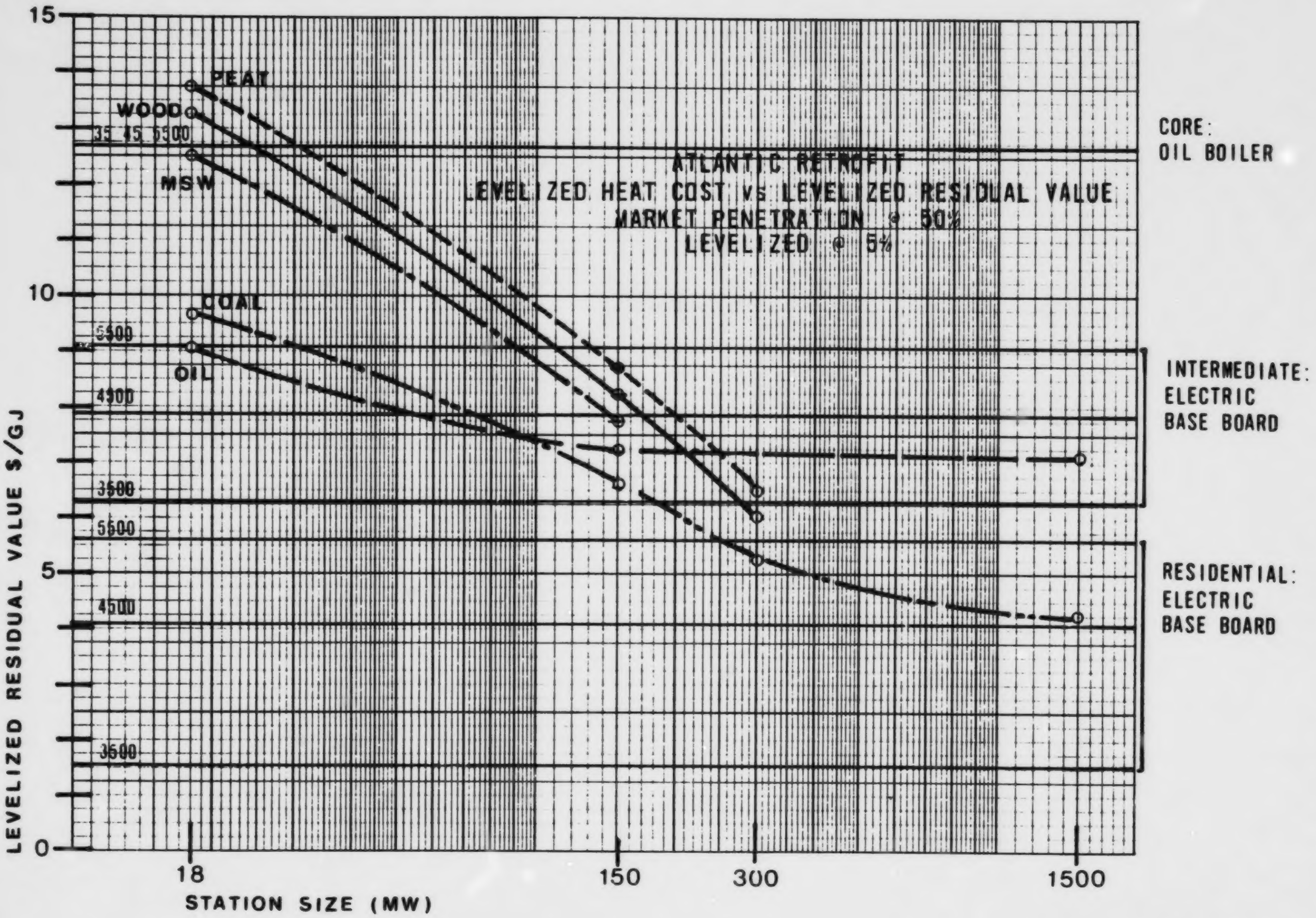
ATLANTIC RETROFIT
LEVELIZED HEAT COST vs LEVELIZED RESIDUAL VALUE
MARKET PENETRATION @ 50%
LEVELIZED @ 5%
PEAT
WOOD
MSW
COAL
OIL
35 45 5500
5500
4900
3500
5500
4500
3500
CORE:
OIL BOILER
INTERMEDIATE:
ELECTRIC
BASE BOARD
RESIDENTIAL:
ELECTRIC
BASE BOARD
LEVELIZED RESIDUAL VALUE $/GJ
0
5
10
15
STATION SIZE (MW)
18
150
300
1500

FIGURE 9-6

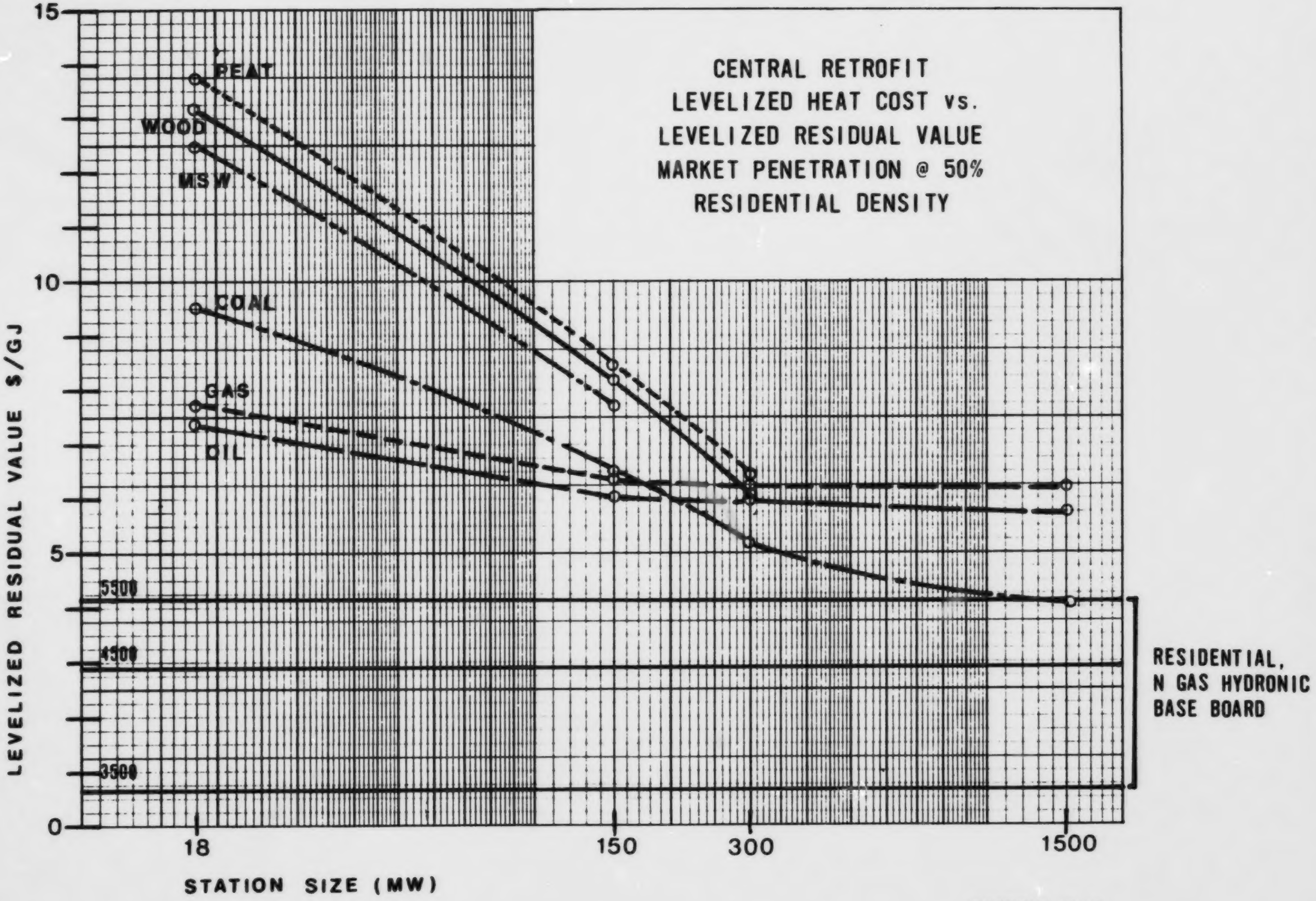
CENTRAL RETROFIT
LEVELIZED HEAT COST vs.
LEVELIZED RESIDUAL VALUE
MARKET PENETRATION @ 50%
RESIDENTIAL DENSITY
PEAT
WOOD
MSW
COAL
GAS
OIL
5500
4500
3500
RESIDENTIAL,
N GAS HYDRONIC
BASE BOARD
15
10
5
0
LEVELIZED RESIDUAL VALUE $/GJ
18
150
300
1500
STATION SIZE (MW)

FIGURE 9-71

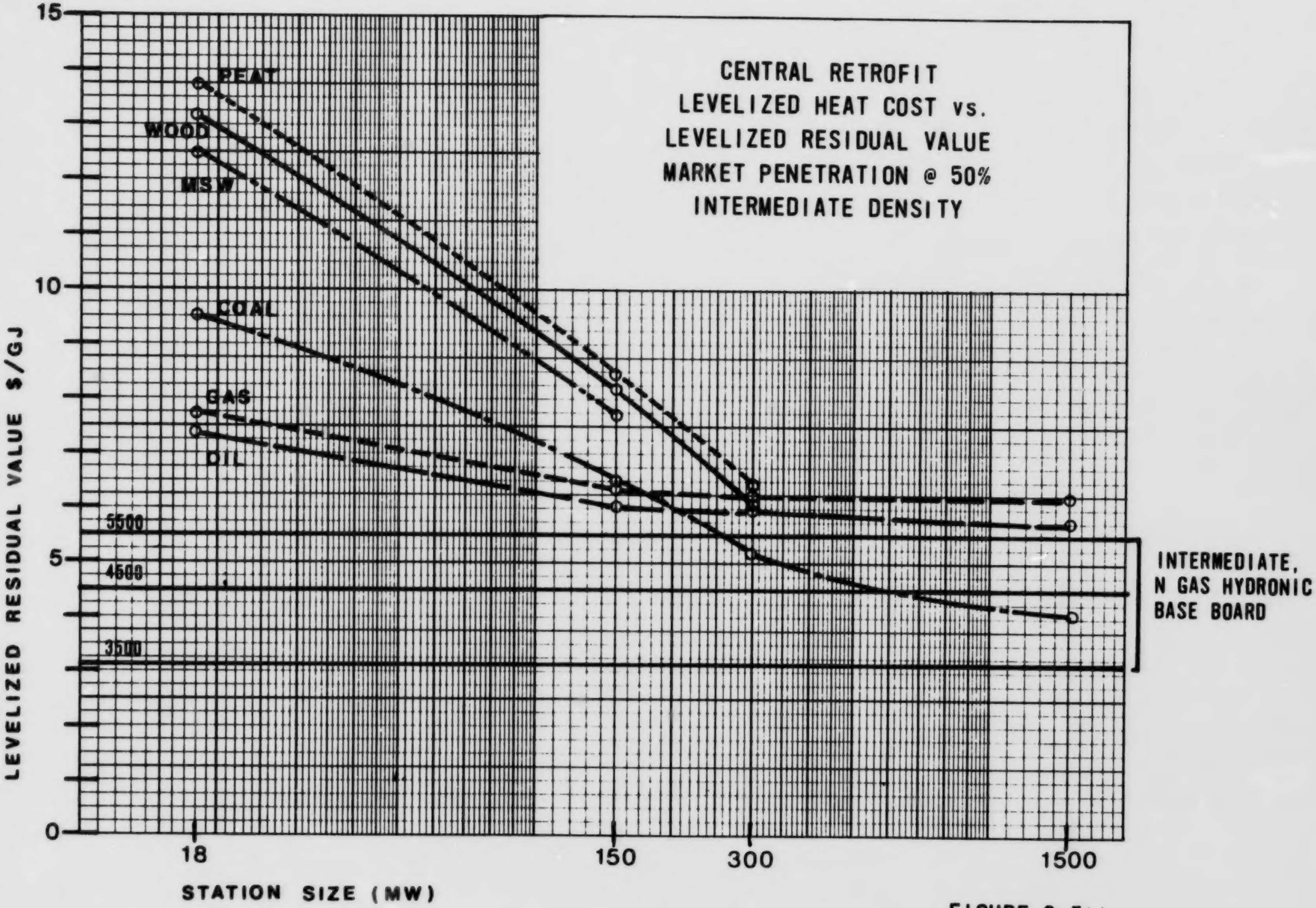
CENTRAL RETROFIT
LEVELIZED HEAT COST vs.
LEVELIZED RESIDUAL VALUE
MARKET PENETRATION @ 50%
INTERMEDIATE DENSITY
PEAT
WOOD
MSW
COAL
GAS
OIL
5500
4500
3500
INTERMEDIATE,
N GAS HYDRONIC
BASE BOARD
LEVELIZED RESIDUAL VALUE $/GJ
15
10
5
0
STATION SIZE (MW)
18
150
300
1500

FIGURE 9-7ii

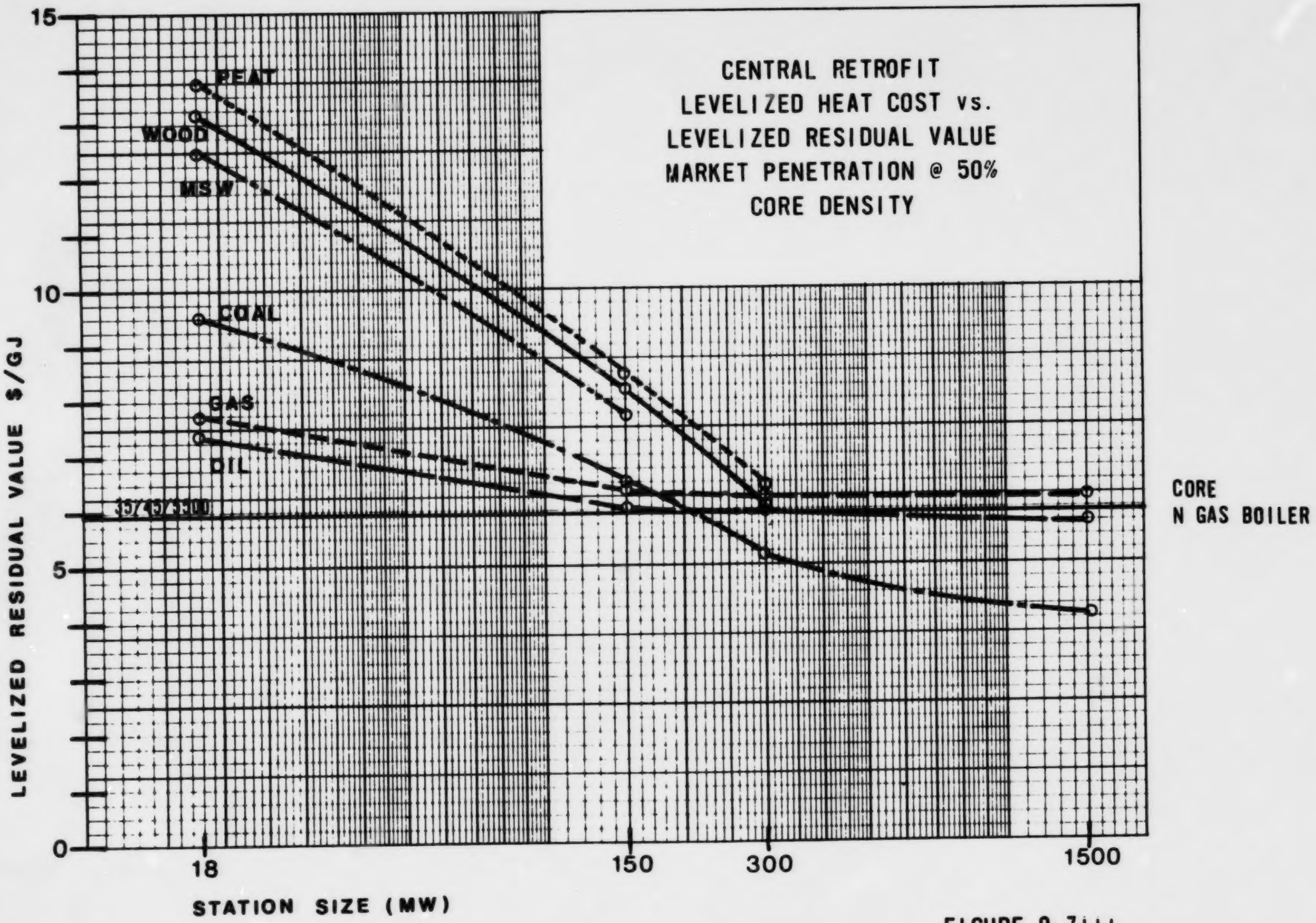

FIGURE 9-7iii

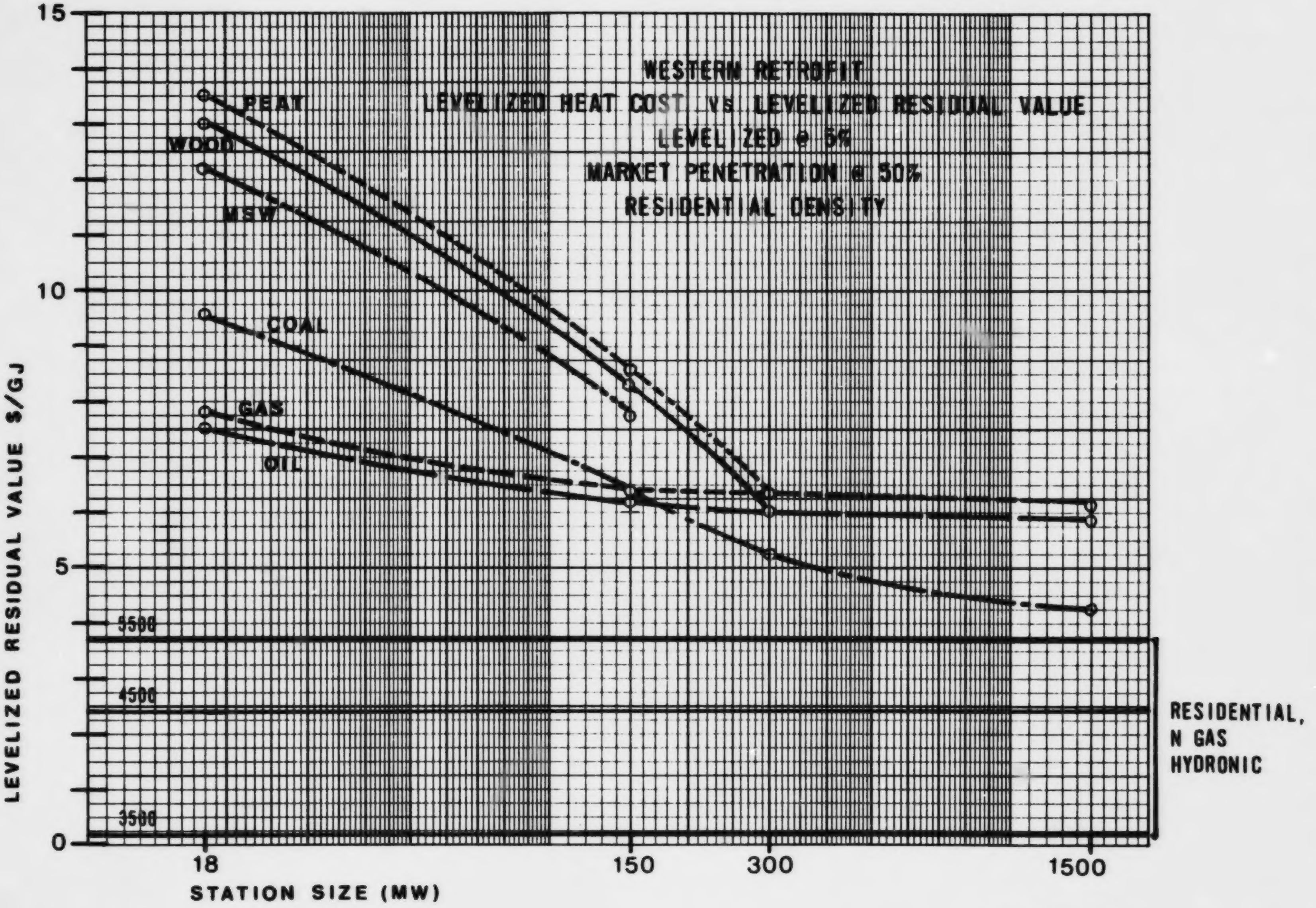
WESTERN RETROFIT
LEVELIZED HEAT COST Vs LEVELIZED RESIDUAL VALUE
LEVELIZED @ 5%
MARKET PENETRATION @ 50%
RESIDENTIAL DENSITY
PEAT
WOOD
MSW
COAL
GAS
OIL
5500
4500
3500
RESIDENTIAL,
N GAS
HYDRONIC
15
10
5
0
LEVELIZED RESIDUAL VALUE $/GJ
18
150
300
1500
STATION SIZE (MW)

FIGURE 9-81

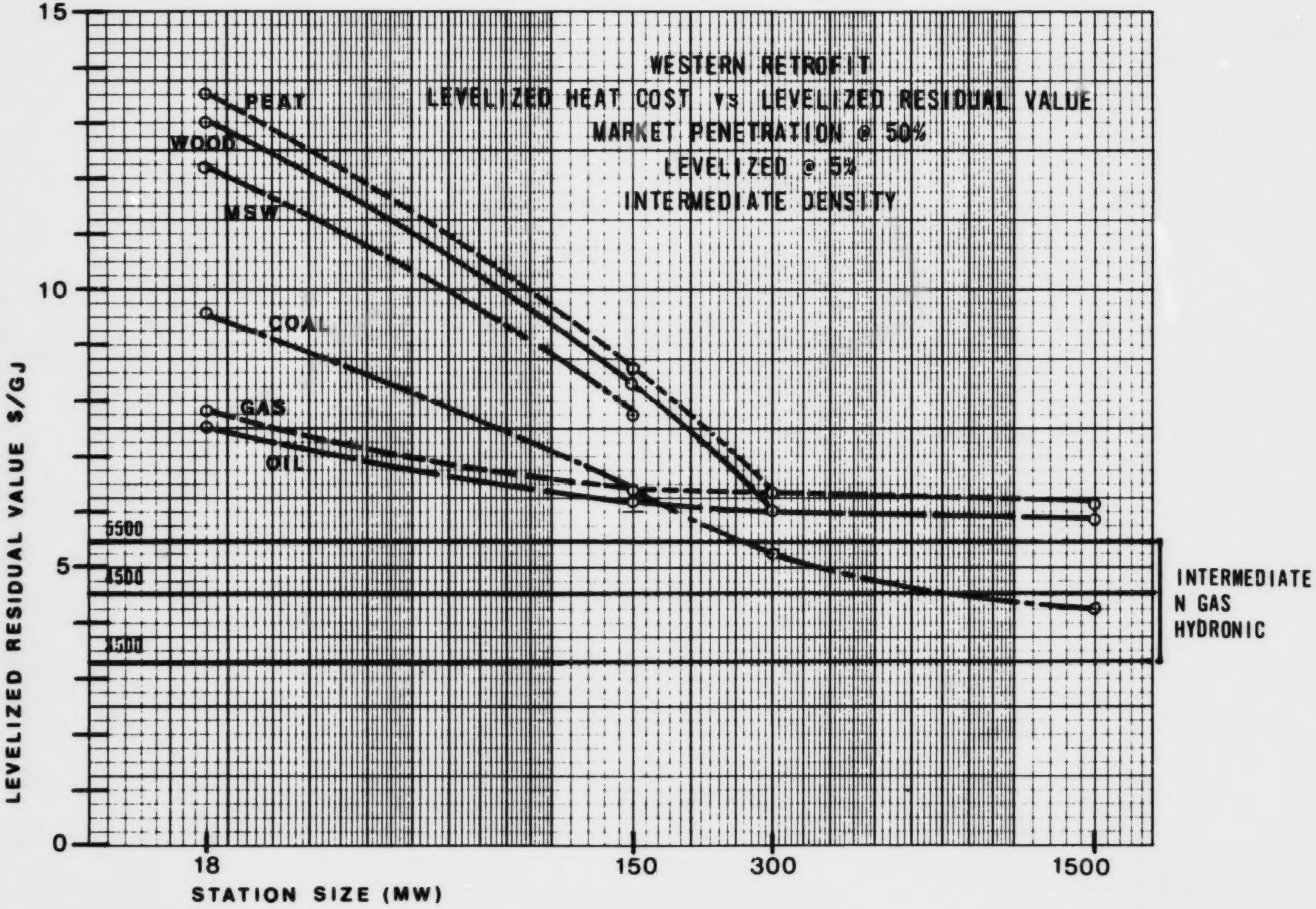
WESTERN RETROFIT
LEVELIZED HEAT COST vs LEVELIZED RESIDUAL VALUE
MARKET PENETRATION @ 50%
LEVELIZED @ 5%
INTERMEDIATE DENSITY
PEAT
WOOD
MSW
COAL
GAS
OIL
5500
4500
3500
INTERMEDIATE
N GAS
HYDRONIC
15
10
5
0
LEVELIZED RESIDUAL VALUE $/GJ
18
150
300
1500
STATION SIZE (MW)

FIGURE 9-8II

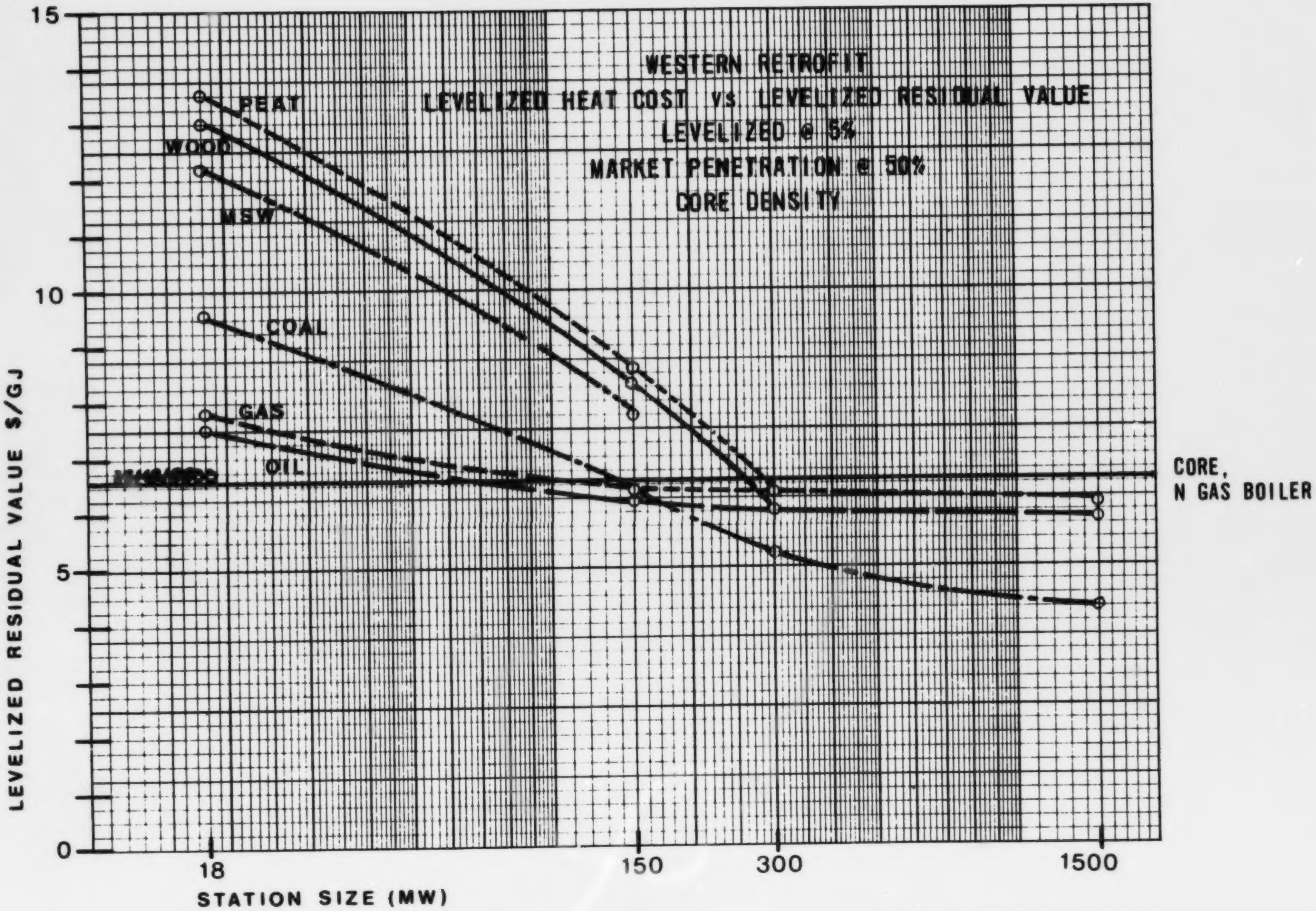

FIGURE 9-8111

TABLE 9-15

Market Penetration @ 50%
Residual Value of 50% Cases as Percent of Residual Value of 100% Cases

Region	Residential			Intermediate			Core		
	EBB	NG Hot Air	LFO Hot Air	EBB	NG Hot Air	LFO Hot Air	NG	Oil	Electric
	%	%	%	%	%	%	%	%	%
Atlantic 4500	65	70	79	89	88	91	96	96	97
Central 4500	49	62	77	83	81	90	93	96	95
Western 4500	51	59	79	80	82	91	93	96	95

As discussed earlier, while Figures 9-6, 9-7 and 9-8 indicate whether district heating offers any savings over conventional heating alternatives, they do not indicate percentage savings over conventional heating alternatives. This information is provided in Tables 9-16, 9-17, and 9-18 in a format similar to that in the primary analysis for the Atlantic, Central, and Western regions respectively. The percentage benefits shown in these tables, are as expected, somewhat lower than the 100 market penetration case (Tables 9-9, 9-10, and 9-11) and in some of the residential and intermediate heat loads the benefits are eliminated entirely. These tables do not show the full impact of the reduction in market penetration on the viability of district heating, since the reduction in plant size and the impact of the resulting increase in the unit cost of heat production is not evident in these tables. The full impact of a reduction in market penetration on the economies of district heating is more clearly demonstrated in Part 9-4 - Opportunity Analysis.

.2 Discount Rate

The primary analysis has been carried out using a five per cent discount rate. Sensitivity analyses using discount rates of three and seven per cent have been conducted on the Atlantic Region cases in order to determine the impact of varying costs of capital on the economic viability of district heating. The results of these analyses are presented in Tables 9-19 and 9-20 for the three per cent and seven per cent cases respectively. These results can be compared to the five per cent discount rate case by reference to Table 9-9. A review of these tables shows that a reduction in the discount rate from five to three per cent has a positive impact on the economic attractiveness of district heating. Looking, for example, at the 150 MW station size, with a two per cent reduction in the discount rate, the maximum benefit for the core heat load density increases from 45 to 50 per cent. For the intermediate heat load density, it increases from 16 to 25 per cent. Finally, for the residential load density, it increases from no benefit to 8 per cent.

TABLE 9-16

Atlantic Retrofit
Benefit Analysis
Market Penetration @ 50%
Percentage Benefit: D.H. vs Least Cost Conventional System

Density @ 4500 DD	Station Size 18 MW	 150 MW	 300 MW
	(%)	(%)	(%)
Core (LFO Boiler)			
Minimum	1 (MSW)	27 (Peat)	35 (Oil)
Maximum	23 (Oil)	41 (Coal)	50 (Coal)
Intermediate (Electric Baseboard)			
Minimum	-	1 (Oil)	2 (Oil)
Maximum	-	8 (Coal)	17 (Coal)
Residential (Electric Baseboard)			
Minimum	-	-	-
Maximum	-	-	-

TABLE 9-17

Central Retrofit
Benefit Analysis
Market Penetration @ 50%
Percentage Benefit: D.H. vs Least Cost Conventional System

Density @ 4500 DD	Station Size 18 MW (%)	 150 MW (%)	 300 MW (%)
Core (Natural Gas Boiler)			
Minimum	-	-	2 (Oil)
Maximum	-	12 (Oil)	10 (Coal)
Intermediate (Natural Gas Hydronic Baseboard)			
Minimum	-	-	-
Maximum	-	-	-
Residential (Natural Gas Hydronic Baseboard)			
Minimum	-	-	-
Maximum	-	-	-

TABLE 9-18

Western Retrofit
Benefit Analysis
Market Penetration @ 50%
Percentage Benefit: D.H. vs Least Cost Conventional System

Density @ 4500 DD	Station Size 18 MW	 150 MW	 300 MW
	(%)	(%)	(%)
Core (Natural Gas Boiler)			
Minimum	-	2 (Coal)	3 (Peat)
Maximum	-	5 (Oil)	17 (Coal)
Intermediate (Natural Gas Hydronic Baseboard)			
Minimum	-	-	-
Maximum	-	-	-
Residential (Natural Gas Hydronic Baseboard)			
Minimum	-	-	-
Maximum	-	-	-

TABLE 9-19

Atlantic Retrofit
Benefit Analysis (3% Sensitivity Analysis)
Percentage Benefit: D.H. vs Least Cost Conventional System

Density @ 4500 DD	Station Size		
	18 MW	150 MW	300 MW
	(%)	(%)	(%)
Core (LFO Boiler)			
Minimum	6 (Peat)	36 (Peat)	40 (Oil)
Maximum	31 (Coal)	49 (Coal)	56 (Coal)
Intermediate (Electric Baseboard)			
Minimum	4 (Oil)	11 (Peat)	16 (Oil)
Maximum	6 (Coal)	25 (Coal)	33 (Coal)
Residential (Electric Baseboard)			
Minimum	-	1 (MSW)	9 (Peat)
Maximum	-	8 (Coal)	18 (Coal)

TABLE 9-20

Atlantic Retrofit
Benefit Analysis (7% Sensitivity Analysis)
Percentage Benefit: D.H. vs Least Cost Conventional System

Density @ 4500 DD	Station Size 18 MW	 150 MW	 300 MW
	(%)	(%)	(%)
Core (LFO Boiler)			
Minimum	16 (Coal)	23 (Peat)	37 (Oil)
Maximum	23 (Oil)	39 (Coal)	49 (Coal)
Intermediate (Electric Baseboard)			
Minimum	-	2 (Oil)	3 (Oil)
Maximum	-	6 (Coal)	16 (Coal)
Residential (Electric Baseboard)			
Minimum	-	-	-
Maximum	-	-	-

Increasing the discount rate from five per cent to seven per cent on the other hand, has a negative effect on district heating. Again, by way of example, at the 150 MW station size, with a two per cent increase in the discount rate, the maximum benefit for the core heat load density decreases from 45 per cent to 40 per cent. For the intermediate heat load density it decreases from 16 to 7 per cent. For the residential heat load density, there continues to be no benefit. These results reflect the higher level of capital investment associated with the installation of a new district heating system and retrofitting of existing subscriber heating equipment to accomodate district heating as compared to continuing in the use of the least cost conventional heating alternative.

.3 Greenfield Developments

The primary economic analysis is based on serving the heating needs of existing commercial buildings and housing stock with district heating. In this analysis many of the capital costs of the existing subscriber heating systems have been considered to be essentially sunk costs and have not been included in cost comparisons with district heating. In addition, the capital costs of installing a DH distribution system in built-up areas and retrofitting existing buildings to accept district heating, usually results in higher capital costs for district heating than would be expected in an entirely new development or greenfield situation. Both of these factors, while valid reflections of the real world, nevertheless place district heating at a competitive disadvantage relative to conventional energy alternatives. Consequently, sensitivity analyses have been carried out to examine the economic feasibility of district heating in a greenfield situation.

In the analyses the full capital costs for subscriber systems for both conventional and DH systems as developed in Part 8 of the report have been included along with the capital costs of the DH distribution and heat production systems. Operation and maintenance costs as developed for the primary analysis have also been included. With respect to the capital costs associated with the installation of distribution systems for conventional energy forms, it has been assumed that there would be no additional charge to the consumer for these facilities above the normal price for the energy. While utilities do require contributions to aid construction in certain instances, such as for extended service drops or service requirements outside their normal standard services, it has been assumed for purposes of this analysis that the service requirements and load density of the greenfield area would be such that no contributions would be required. It has also been assumed that the residential heat load density assumed for the study would be the most appropriate for the greenfield development since intermediate and core heat loads would normally be expected to develop over extended time periods. The costs assumed for the Atlantic Region where, on the basis of the primary analysis, district heating appears most competitive, have been used in the analyses.

Two cases have been examined. In the first case, district heating has been compared with electric baseboard heating as in the primary analysis. In the second case, recognizing that in a greenfield situation the method of utilizing conventional energy forms might change, district heating has been compared with natural gas using a high efficiency condensing type furnace. The results of the analyses, with benefits from district heating again expressed in terms of the percentage savings over the conventional energy alternative, are presented in Table 9-21. In addition the comparable results for the retrofit case have been reproduced from Table 9-9. It can be seen from the table that the benefits of district heating as compared to electric baseboard heating are enhanced for the larger station sizes in the greenfield situation. However, when compared to natural gas (assuming availability of gas from the Venture Gas Field) burned in a condensing type furnace no benefit is achieved with district heating.

TABLE 9-21

Atlantic Region
Benefit Analysis @ 5%
Percentage Benefit: D.H. vs Least Cost Conventional System

Density @ 4500 DD	Station Size		
	18 MW	150 MW	300 MW
	(%)	(%)	(%)
Retrofit Residential (Electric Baseboard)			
Minimum	-	-	1 (Wood)
Maximum	-	-	8 (Coal)
Greenfield Residential (Electric Baseboard)			
Minimum	-	3 (Wood)	10 (Oil)
Maximum	-	17 (Coal)	26 (Coal)
Greenfield Residential (Natural Gas Condensing Type Furnace)			
Minimum	-	-	-
Maximum	-	-	8 (Coal)

Note: [1] Residential Greenfield only considered for analysis

.4 Cogeneration

The primary analysis has been based on the cost of heat produced from a heat-only station. As discussed in Part 6, heat can also be produced in conjunction with the production of electricity in cogeneration plants. Sensitivity analyses have been carried out to examine the impact of cogeneration on the economic feasibility of district heating.

Cogeneration plant capital and operating costs developed in Part 6 are based on a high pressure boiler with an extraction turbine to provide base load heat and a low pressure boiler to provide peak load heat. In developing levelized heat production costs the full range of fuels considered in the primary analysis are used for baseload cogeneration units however only gas has been considered for the peaking units. The fuel prices used are based on Central Region prices. Assumptions regarding interim replacement, insurance and taxes as well as escalation of operating costs are the same as for the heat-only plants.

The value of electricity produced in a cogeneration plant is difficult to estimate since it can be affected by a variety of factors. This point is discussed in more detail in Part 11 of the report. For the purposes of these sensitivity analyses, two values were assumed: $0.033/kWh and $0.06/kWh. The former is the amount Ontario Hydro has indicated it is prepared to pay, effective January 1, 1985 to independent producers for electricity generated from units with a minimum availability of 65 per cent. The latter value is indicative of the displacement value of electrical energy in a high energy cost area such as Prince Edward Island. The value of cogenerated electricity has been escalated at the real rate of escalation indicated for the industrial rate for electricity in Ontario as estimated in the EM&R Spring 1984 forecast. The value of cogenerated electricity is then netted against the total capital and operating costs of the cogeneration plant and the remaining capital and operation costs of the plant are, for purposes of the analyses, allocated to the cost of heat production.

The levelized heat costs, based on sale prices of $0.033/kWh and $0.06/kWh for cogenerated electricity, plotted against least cost residual values are presented in Figure 9-9 and 9-10 respectively. Benefit analyses for these two electricity price situations are presented in Tables 9-22 and 9-23.

It is clear from Figure 9-9 and Table 9-22 that $0.033/kWh is insufficient to recover the additional costs associated with cogeneration relative to the heat-only plant for the cogeneration plant configuration assumed. In the case of $0.06/kWh, by way of comparison, the increase in the electric sales credit produces significant percentage benefits for district heating. When a 300 MW cogeneration plant is the heat source the maximum benefit in the core increases from 16 per cent to 49 per cent, for the intermediate it increases from 4 per cent to 37 per cent and for the residential it becomes economical with a 30 per cent benefit.

It should be emphasised that these cogeneration sensitivity analyses are based on the installation of new multiple unit cogeneration plants and the sale of cogenerated electricity to electric utilities typically at fuel or energy replacement value. To the extent that existing facilities could be retrofitted for cogeneration at lower capital costs, and/or electrical output could be utilized by the cogenerator or sold directly to end users at a price above the electric utilities' fuel or energy displacement value, the economics of cogeneration/district heating would improve.

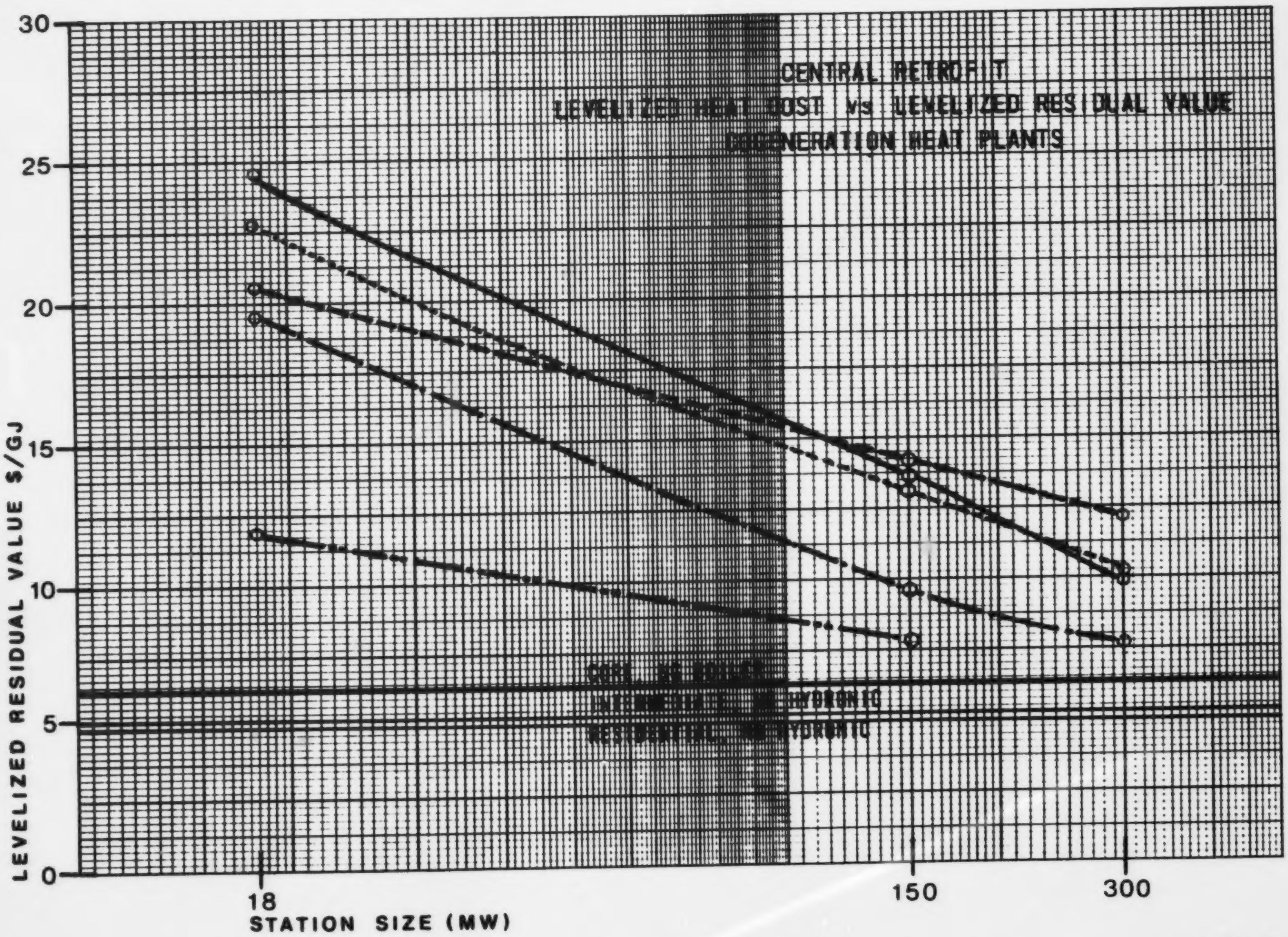
CENTRAL RETROFIT
LEVELIZED HEAT COST vs LEVELIZED RESIDUAL VALUE
COGENERATION HEAT PLANTS
30
25
20
15
10
5
0
LEVELIZED RESIDUAL VALUE $/GJ
18
150
300
STATION SIZE (MW)
COML. OB BOILER
INTERMEDIATE OB HYDRONIC
RESIDENTIAL OB HYDRONIC

FIGURE 9-9

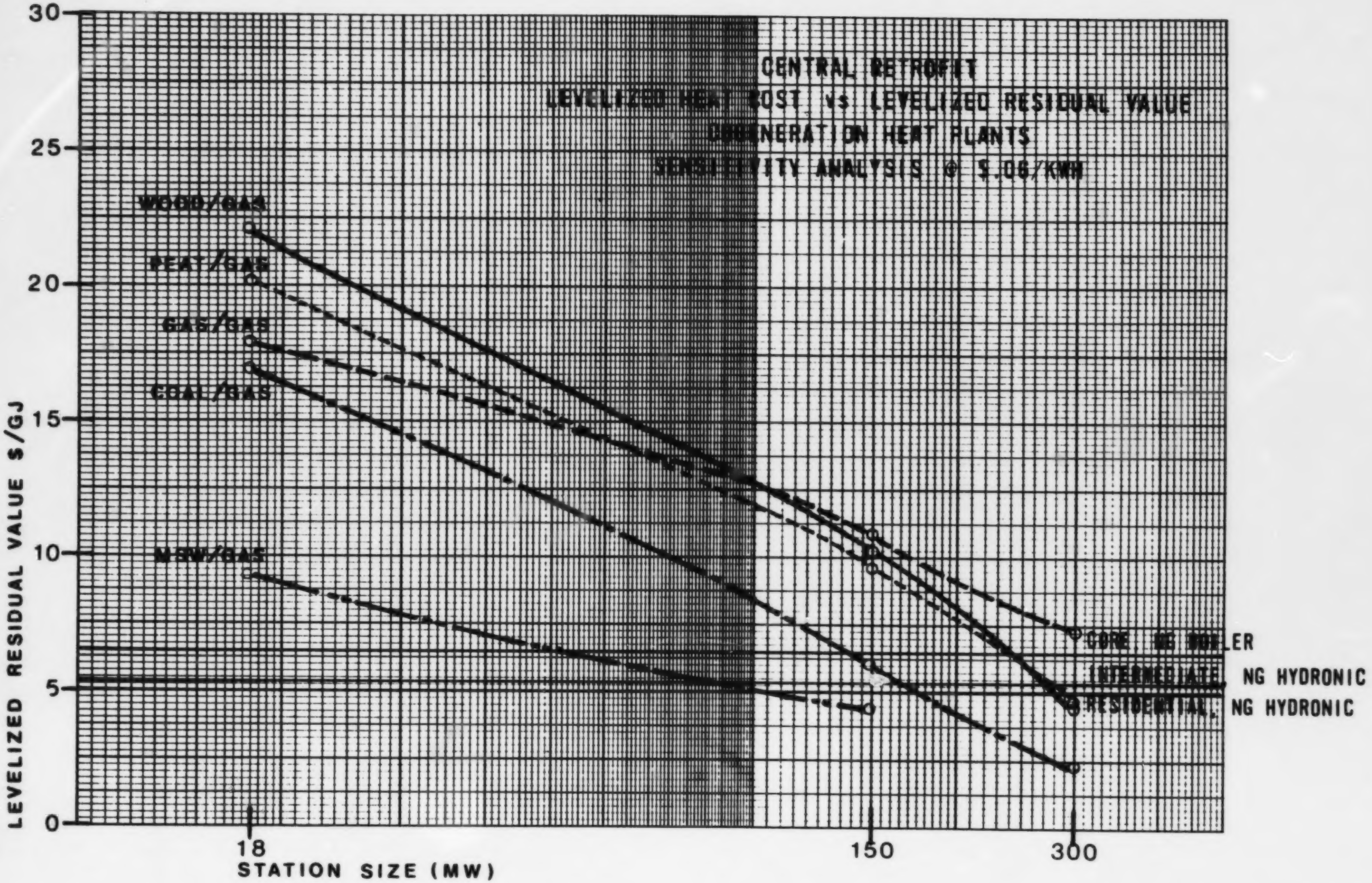
CENTRAL RETROFIT
LEVELIZED HEAT COST vs LEVELIZED RESIDUAL VALUE
COGENERATION HEAT PLANTS
SENSITIVITY ANALYSIS @ $.06/KWH
LEVELIZED RESIDUAL VALUE $/GJ
0
5
10
15
20
25
30
STATION SIZE (MW)
18
150
300
WOOD/GAS
PEAT/GAS
GAS/GAS
COAL/GAS
MSW/GAS
CORE, NG BOILER
INTERMEDIATE, NG HYDRONIC
RESIDENTIAL, NG HYDRONIC

FIGURE 9-10

TABLE 9-22

Central Retrofit
Benefit Analysis (Cogeneration - $0.033/kWh)
Percentage Benefit: D.H. vs Least Cost Conventional System

Density @ 4500 DD	Station Size 18 MW	 150 MW	 300 MW
	(%)	(%)	(%)
Core (Natural Gas Boiler)			
Minimum	-	-	-
Maximum	-	-	-
Intermediate (Natural Gas Hydronic Baseboard)			
Minimum	-	-	-
Maximum	-	-	-
Residential (Natural Gas Hydronic Baseboard)			
Minimum	-	-	-
Maximum	-	-	-

TABLE 9-23

Central Retrofit
Benefit Analysis (Cogeneration - $0.060/kWh)
Percentage Benefit: D.H. vs Least Cost Conventional System

Density @ 4500 DD	Station Size 18 MW (%)	 150 MW (%)	 300 MW (%)
Core (Natural Gas Boiler)			
Minimum	-	4 (Coal)	21 (Peat)
Maximum	-	25 (MSW)	49 (Coal)
Intermediate (Natural Gas Hydronic Baseboard)			
Minimum	-		8 (Peat)
Maximum	-	11 (MSW)	37 (Coal)
Residential (Natural Gas Hydronic Baseboard)			
Minimum	-	-	3 (Peat)
Maximum	-	6 (MSW)	30 (Coal)

.5 Low Grade Fuel Escalation Rates

The primary analysis is based on coal, wood, peat and municipal solid waste prices escalating at the rate estimated for coal in the EM&R Spring 1984 forecast. As can be seen from Table 9-1, the real cost of coal is forecast to decrease significantly in the early years of the forecast. This expected decrease in the real cost of coal is due in part to expected shifts in the location of coal consumption. A sensitivity analysis assuming that coal, wood, peat and municipal solid waste prices increase at the general rate of inflation has been carried out for the Atlantic Region. Figure 9-11 shows levelized least cost residual values plotted against levelized heat costs assuming the higher escalation rate for the low grade fuels. Table 9-24 presents the percentage benefit analysis that is estimated for this case. It is clear that in comparing Figure 9-11 to Figure 9-3 and Table 9-24 to Table 9-9 that the higher heat costs do not significantly alter the pattern and values of the benefits associated with district heating. The average benefit decreases 4 percentage points. Consequently, if the low grade fuel types escalate at the general rate of inflation the impact will be felt most significantly in conditions where district heating is marginally attractive. The four percentage point decrease was estimated in the region with the highest cost of energy. In regions with lower cost conventional alternatives the attractiveness of district heating is reduced. Combining this fact with the zero real rate of escalation for low grade fuels, district heat would be beneficial only in high density areas capable of supporting large station sizes which maximize economies of scale or in areas where the cost of locally available low grade energy resources are below the values assumed in the study.

It should be noted that since this report presents residual values associated with a variety of heat load types, climatic environments, and alternative energy pricing regimes, it provides a basis for individual communities to make a preliminary assessment of the viability of district heating based on the costs of locally available heat sources.

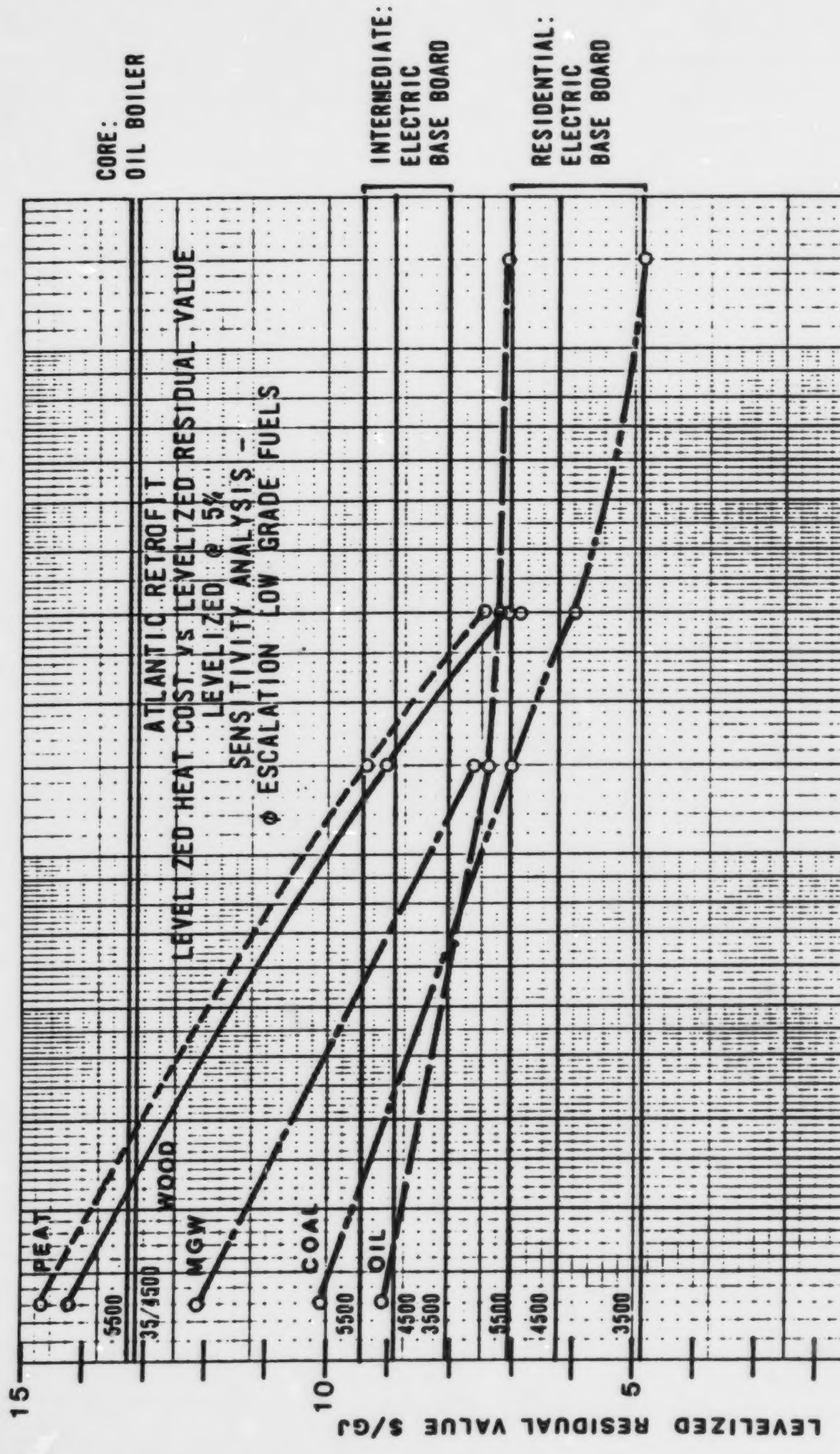
ATLANTIC RETROFIT
LEVELIZED HEAT COST vs LEVELIZED RESIDUAL VALUE
LEVELIZED @ 5%
SENSITIVITY ANALYSIS -
Φ ESCALATION LOW GRADE FUELS
CORE:
OIL BOILER
INTERMEDIATE:
ELECTRIC
BASE BOARD
RESIDENTIAL:
ELECTRIC
BASE BOARD
PEAT
WOOD
MGW
COAL
OIL
5500
35/4500
5500
4500
3500
5500
4500
3500
LEVELIZED RESIDUAL VALUE $/GJ
15
10
5
0
STATION SIZE (MW)
18
150
300
1500

FIGURE 9-11

TABLE 9-24

Atlantic Retrofit
Benefit Analysis @ 5%
Percentage Benefit: D.H. vs Conventional Heating System
Sensitivity Analysis: 0 Escalation Low Grade Fuels

Density @ 4500 DD	Station Size 18 MW	 150 MW	 300 MW
	(%)	(%)	(%)
Core (LFO Boiler)			
Minimum	6 (MSW)	26 (Peat)	40 (Oil)
Maximum	28 (Oil)	40 (Coal)	49 (Coal)
Intermediate (Electric Baseboard)			
Minimum	-	9 (MSW)	10 (Oil)
Maximum	-	12 (Coal)	21 (Coal)
Residential (Electric Baseboard)			
Minimum	-	-	-
Maximum	-	-	4 (Coal)

9.4 OPPORTUNITY ANALYSIS

Using the results of the economic analysis and the heat load characteristics estimated for the "Canadian Model" developed in Part 5 of the report, a preliminary analysis of the potential for district heating for each of the three geographic regions has been carried out.

As a first step, the useful heat requirement for each city in the Atlantic, Central and Western Regions listed in Table 5-3 is estimated on the basis of its population and the estimated per capita heat consumption as indicated in Table 5-6. The total useful heat requirement for each city is then allocated among the various heat load densities as shown in Table 5-6: the core; 200 MJ/m^2 and above (excluding the core); 100-199 MJ/m^2; and 0-99 MJ/m^2. As discussed in Part 7, this latter heat load density is not considered large enough to support district heating and therefore is excluded from the analysis.

The allocated heat requirements are then used to determine the heat plant size required to serve:

(i) all heat loads equal to or greater than 100 MJ/m^2 (residential, intermediate and core heat loads).

(ii) all heat loads equal to or greater than 200 MJ/m^2 (intermediate and core heat loads).

(iii) core heat load only.

Plant sizes are determined on the basis of the constant heat demand characteristics of 2700 hours of utilization, an 80 per cent diversity factor, and five per cent distribution losses. As discussed earlier the maximum plant size has been limited to 300 MW.

This approach is based on a single heat plant (up to a maximum size of 300 MW) serving a city or town and no provision is made for transmission requirements. To the extent that it is considered impractical to service a heat load concentration from a single source located close to the load center, this could reduce the potential for district heating calculated on this basis.

The second step of the analysis is carried out on two alternative bases. In one case some of the economic benefits of district heating in high heat load areas are used to subsidize the cost of serving lower heat load density areas. Such cross-subsidization would be expected to increase the estimate of the heat requirement that could be served by district heating. In the other case no cross-subsidization between core, intermediate or residential heat loads is assumed. This latter analysis would be expected to provide a "lower limit" estimate of the heat requirment that could be served by district heating.

The analysis and results of the "cross-subsidization" are discussed below. Using the heat plant sizes as determined in step one it is possible to determine which fuel types, if any, would result in a levelized heat cost which is less than the weighted average least cost of continuing to serve each of the three mixes of heat loads noted above by conventional heating alternatives. Where the levelized cost of heat is less than the weighted average least cost levelized residual value of the mixed heat loads, this heat load is identified as having potential for district heating and the amount of useful that could be provided by district heating is computed.

It is evident from the foregoing that the screening approach taken to quantify the regional potential for district heating in Canada is very general in nature. Consequently the approach is not sensitive to particular opportunities or impediments that could improve or diminish the economic competitiveness of district heating in specific cities and towns. Therefore, the reader is cautioned against interpreting the results of the analysis for a particular city or town as indicative of its potential for district heating. To the extent however, that the data used in the study are representative of general demographic and climatological conditions and energy pricing regimes within a region, the results for the region can be considered indicative of the potential for district heating in the region.

941 ATLANTIC REGION

The opportunity analysis for the Atlantic Region based on cross-subsidization is presented in Table 9-25. The table indicates that the annual useful heat requirement for the residential and commercial sectors for the cities in the Atlantic Region that passed the initial population and population density screens outlined in Part 5 is estimated to be 24.72 PJ. Assuming 100 per cent market penetration, it is estimated that district heating could economically supply 11.22 PJ or about 45 per cent of this requirement. While about 45 per cent of this potential or about 5 PJ is associated with the region's two largest centers, economic feasibility is fairly broadly based with district heating estimated to provide some economic benefit in virtually all centers. If only 50 per cent market penetration is achieved in areas where district heating appears economical, the reduction in heat plant size and the consequent increase in unit heat costs would reduce the economic attractiveness of district heating. Consequently, the estimated amount of heat that could be supplied by district heating would be reduced to 2.49 PJ or about 10 per cent of the annual requirement.

As would be expected, due to decreasing heat plant sizes as one moves from larger to smaller cities and towns, the loss in economies of scale in the heat plant results in residential heat loads becoming uneconomical to supply with district heating.

Table 9-25

Regional Opportunity Analysis
Atlantic Region

City	Population(1)	Annual Heat Consumption Per Capita(2)	Annual Heat Consumption - City -	District Heating 100% Penetration				District Heating 50% Penetration			
				Load(3) Type	Plant Size	Energy	Fuel(4) Types	Load(3) Type	Plant Size	Energy	Fuel(4) Types
	10³	GJ	PJ		MW	PJ			MW	PJ	
Halifax	115	45	5.18	R	221	2.59	O,P,C,W	I	44	.52	O,C,M
St. John's	110	45	4.95	R	212	2.48	O,P,C,W	I	42	.50	O,C,M
Saint John	73	45	3.29	R	141	1.65	O,C,M	I	28	.33	C,O
Dartmouth	62	45	2.79	R	119	1.39	O,C	I	24	.28	C,O
Moncton	53	45	2.39	R	102	1.19	O,C	I	20	.24	C,O
Sydney	51	45	2.30	R	98	1.15	O,C	I	20	.23	C,O
Corner Brook	24	45	1.08	I	19	.22	O,C	I	9	.11	C,O
Sydney Mines	19	45	.86	I	15	.18	O,C	I	7	.08	O
Charlottetown	17	45	.77	I	13	.15	O,C	I	7	.08	O
New Glasgow	10	45	.45	I	8	.09	O,C	I	4	.05	O
Labrador City	12	55	.66	I	11	.13	O,C	I	6	.07	O
Totals	546	-	24.72	-	-	11.22	-	-	-	2.49	-

Notes:
1. See Table 5-3.
2. See Table 5-6.
3. R - heat loads above 100 MJ/m^2 (residential, intermediate and core).
   I - heat loads above 200 MJ/m^2 (intermediate and core).
   C - core heat loads.
4. Fuel Types: O - oil, P - peat, W - wood/biomass, C - coal, M - municipal solid waste, G - gas.
5. * District heating is not economically beneficial.

CENTRAL REGION

The district heating opportunity analysis for the Central Region based on cross-subsidization is presented in Table 9-26. The table indicates that the annual useful heat requirement for the residential and commercial sector for cities in the Central Region that passes the initial population and population density screens is estimated to be 410.54 PJ. The larger centres of Toronto and Montreal are considered with two levels of distribution by heat density, one for the core of the city and another for the remaining areas making up the balance of the metropolitan population.

If district heating could achieve 100 per cent market penetration in the areas where it appears economically attractive, it is estimated that district heating could economically supply 203.62 PJ or about 50 per cent of this requirement. Economic potential however, is much more heavily concentrated in the larger centers than is the case in the Atlantic Region. District heating appears economic in only the 14 largest centers of the total of 48 cities and towns in the region included in the analysis and the two largest represent about 77 per cent of the total potential. If only 50 per cent market penetration could be achieved, reduced economies of scale would result in the amount of useful heat that could be supplied by district heating being reduced to 49.22 PJ or about 5 per cent of the annual requirement.

Table 9-26

Regional Opportunity Analysis
Central Region

City	Population	Annual Heat Consumption Per Capita	Annual Heat Consumption - City -	Load(3) Types	District Heating 100% Penetration Plant Size	District Heating 100% Penetration Energy	Fuel(4) Types	Load(3) Types	District Heating 50% Penetration Plant Size	District Heating 50% Penetration Energy	Fuel(4) Types
	10^3	GJ	PJ		MW	PJ			MW	PJ	
Toronto (Other)	2212	45	99.54	R	4255	49.77	C	I	851	9.95	C
Montreal (Other)	1571	45	70.70	R	3022	35.35	C	I	604	7.07	C
Montreal (Core)	1080	45	48.60	R	4030	47.14	C	I	1770	20.70	C
Toronto (Core)	600	45	27.00	R	2171	25.40	C	I	981	11.50	C
Quebec	476	55	26.18	R	1119	13.10	C,O	C	99	1.16	O
Ottawa	389	45	17.51	R	748	8.75	C	C	75	*	*
Hamilton	326	35	11.41	R	488	5.71	C	C	49	*	*
London	254	45	11.43	R	489	5.72	C	C	49	*	*
Windsor	212	35	7.42	R	317	3.71	C	C	32	*	*
Hull	149	45	6.71	R	287	3.36	C	C	29	*	*
Kitchener	139	45	6.26	R	268	3.13	C	C	27	*	*
St. Catharines	124	35	4.34	C	37	.43	O	C	19	*	*
Chicoutimi	110	45	4.95	C	42	.50	O	C	21	*	*
Thunder Bay	100	55	5.50	C	47	.55	O	C	24	*	*
Oshawa	100	45	4.50	C	38	.45	O	C	19	*	*
Sudbury	100	55	5.50	C	47	.55	O	C	24	*	*
Sherbrooke	83	45	3.74	C	32	*	*	C	16	*	*
Kingston	75	45	3.38	C	29	*	*	C	14	*	*
Sault Ste. Marie	75	55	4.13	C	35	*	*	C	18	*	*
Brantford	72	35	2.52	C	22	*	*	C	11	*	*
Guelph	71	45	3.20	C	27	*	*	C	14	*	*
Peterborough	61	45	2.75	C	23	*	*	C	12	*	*
Sarnia	51	35	1.79	C	15	*	*	C	8	*	*
Shawinigan	47	55	2.59	C	22	*	*	C	11	*	*
Chatham	41	35	1.44	C	12	*	*	C	6	*	*
Drummondville	39	45	1.76	C	15	*	*	C	8	*	*
Barrie	38	45	1.71	C	15	*	*	C	7	*	*
St. Hyacinthe	38	45	1.71	C	15	*	*	C	7	*	*
Belleville	35	45	1.58	C	13	*	*	C	7	*	*
Trois Rivières	32	45	1.44	C	12	*	*	C	6	*	*
Valleyfield	30	45	1.35	C	12	*	*	C	6	*	*
Rimouski	28	55	1.54	C	13	*	*	C	7	*	*
Sept-Isles	26	55	1.43	C	12	*	*	C	6	*	*
Stratford	26	45	1.17	C	10	*	*	C	5	*	*
St. Jean	25	45	1.13	C	10	*	*	C	5	*	*
St. Jerome	25	55	1.38	C	12	*	*	C	6	*	*
Orillia	24	45	1.08	C	9	*	*	C	5	*	*
Sorel	23	45	1.04	C	9	*	*	C	4	*	*
Victoriaville	22	45	.99	C	8	*	*	C	4	*	*
Thetford Mines	20	55	1.10	C	9	*	*	C	5	*	*
Brockville	20	45	.90	C	8	*	*	C	4	*	*
Owen Sound	20	45	.90	C	8	*	*	C	4	*	*
Val D'Or	19	55	1.05	C	9	*	*	C	5	*	*
Cobourg	16	45	.72	C	6	*	*	C	3	*	*
Trenton	15	45	.68	C	6	*	*	C	3	*	*
Lindsay	14	45	.63	C	5	*	*	C	3	*	*
Pembroke	14	45	.63	C	5	*	*	C	3	*	*
Rivière-du-Loup	13	55	.72	C	6	*	*	C	3	*	*
Leamington	13	35	.46	C	4	*	*	C	2	*	*
Hawkesbury	10	45	.45	C	4	*	*	C	2	*	*
Totals	9103	-	410.54	-	-	203.62			-	49.22	-

Notes: 1-5 Same
6. Toronto/Montreal estimates based on heat load distributions that differ for core/other on the basis of Table 5 6.

943 WESTERN REGION

The district heating opportunity analysis for the Western Region based on cross-subsidization is presented in Table 9-27. The table indicates that the annual useful heat requirement for the residential and intermediate sector for cities in the Western Region that passes the initial population and population density screens is estimated to be 163.67 PJ. Similar to Montreal and Toronto, Vancouver has been considered with two levels of heat density distribution. With 100 per cent market penetration in areas where it appears economically attractive it is estimated that district heating could economically supply 80.64 PJ or about 49 per cent of this requirement. With 50 per cent market penetration the amount of useful heat that could be supplied by district heating would be reduced to 10.65 PJ or about 5 per cent of the annual requirement.

Results in the Western Region are similar to the Central Region both in percentage terms and in the concentration of economic potential for district heating in the 7 largest of the 16 cities and towns in the region included in the analysis. The concentration of potential for district heating primarily in the largest centers in the Central and Western regions occurs because of the availability of low cost natural gas. The availability of this low cost conventional energy form more than offsets, for all but the largest centers, the greater potential for economies of scale available to district heating as a result of these regions having greater numbers of large population concentrations than the Atlantic Region.

Table 9-27

Regional Opportunity Analysis
Western Region

City	Population	Annual Heat Consumption Per Capita	Annual Heat Consumption - City -	District Heating 100% Penetration				District Heating 50% Penetration			
				Load Types	Plant Size	Energy	Fuel Types	Load Types	Plant Size	Energy	Fuel Types
	10^3	GJ	PJ		MW	PJ			MW	PJ	
Calgary	593	55	32.62	R	1385	16.31	C	I	279	3.26	C
Winnipeg	564	55	31.02	R	1326	15.51	C	I	265	3.10	C
Vancouver - bal(6)	555	35	19.43	R	831	9.72	C	C	83	.97	O
Edmonton	549	55	30.20	R	1291	15.10	C	C	129	1.51	O
Vancouver (centre)	414	35	14.49	R	1202	14.06	C	C	155	1.81	O,G
Victoria	177	35	6.20	T	106	1.24	G,O	C	27	*	*
Regina	162	55	8.91	R	381	4.46	C	C	38	*	*
Saskatoon	154	55	8.47	R	362	4.24	C	C	36	*	*
Kamloops	55	35	1.93	C	17	*	*	C	9	*	*
Lethbridge	54	45	2.43	C	21	*	*	C	11	*	*
Red Deer	46	55	2.53	C	22	*	*	C	11	*	*
Moose Jaw	34	55	1.87	C	16	*	*	C	8	*	*
Port Albernia	20	35	.70	C	6	*	*	C	3	*	*
Vernon	20	35	.70	C	6	*	*	C	3	*	*
Cranbrooke	16	45	.72	C	6	*	*	C	3	*	*
Prince Rupert	15	45	.68	C	6	*	*	C	3	*	*
Thompson	14	55	.77	C	7	*	*	C	3	*	*
Totals	3442	-	163.67	-	-	80.64	-	-	-	10.65	-

Notes: 1-5 Same
6. Vancouver estimated based on heat load distributions that differ for core/other on the basis of Table 5-6.

The results of the opportunity analysis for the each three regions and the summation of the results representing the potential for Canada based on cross-subsidization are presented in Table 9-28.

As can be seen from the table, centers containing a population of 13.1 million, out of a total Canadian population of 24.3 million at the time of the 1981 census, were considered in the analysis. It is estimated that the total requirement for useful heat for residential and commercial space heating and domestic hot water for these population centers is about 600 PJ per year. If one assumes an overall average conversion efficiency of 60 per cent for the conventional systems presently supplying this load and adjusts for population, this results in an estimated heat input requirement for space heating and domestic hot water for the residential and commercial sector in Canada of about 1850 PJ per year. This estimate compares reasonably well with the actual total energy consumption recorded for these sectors in 1981 of about 2100 PJ as indicated in Figure 5-4, particularly when one recognizes that this latter figure includes some energy consumption for process purposes, electrical appliances and lighting.

The table also indicates that of the total useful heat requirement of 600 PJ per year, district heating could economically supply 295 PJ or about 49 per cent of this requirement if 100 per cent market penetration could be achieved on about 10 per cent of the useful heat requirement if 50 per cent market penetration were achieved.

TABLE 9-28

Regional Opportunity Analysis
(With Cross-subsidization)

Region	Population(1)	Annual Heat Consumption(2)	Economically Attractive for District Heating			
			100% Penetration		50% Penetration	
			Energy	Percent	Energy	Percent
	(000's)	PJ	PJ		PJ	
Atlantic	546	24.72	11.22	45	2.49	10
Central	9103	410.54	203.62	50	49.22	12
Western	3442	163.67	80.64	49	10.65	7
Total	13091	598.93	295.48	49	62.36	10

Notes: (1) Population of cities listed in Table 1-4 for each region.

(2) Useful heat.

945 ALTERNATIVE ANALYSIS

The use of a weighted average residual value to determine economic feasibility results in cross-subsidization among heat load types.

As indicated in the economic analysis, the economic benefits of district heating for residential and intermediate heat loads, particularly in the Central and Western regions, are modest or non-existant. Cross-subsidization by the core heat loads (which reduces the economic benefit to the core heat loads) to offset the costs of serving a marginally uneconomic intermediate or residential heat load increases the total heat load that could be economically served by district heating. However it also tends to reduce the benefits of district heating for all heat loads to breakeven with the least cost conventional heating alternative. If the decision to convert to district heating is based solely an economic grounds then, with marginal or no economic incentive for conversion, the methodology of the foregoing opportunity analysis likely produces an estimate of the maximum potential for district heating.

The alternative opportunity analysis, in which there is no cross-subsidization assumed, can be carried out in the same manner as the method just discussed except that instead of comparing levelized heat plant costs to the weighted average residual values of the mixed heat loads, levelized heat plant costs would be compared to the residual value of each heat load type (residential, intermediate and core). For example, if the levelized cost of heat from a heat plant large enough to serve all loads equal to or greater than 100 MJ/m^2 was greater than the residual value for the residential heat load, then the residential heat load would be considered uneconomic and excluded from further analysis. The size of the heat plant would be reduced accordingly to reflect the elimination of the residential heat load and the levelized cost of heat from this smaller plant would be compared to the residual value for the intermediate heat load to determine if it could be economically served. In the event it was also uneconomic, the analysis would the proceed to examine, in a similar manner, the core heat load. This approach eliminates entirely any element of cross-subsidization among the three heat load types.

The results of the opportunity analysis carried out on this basis are presented in summary form in Table 9-29. It can be seen from the table that this approach greatly reduces the economic potential for district heating compared to the opportunity analysis with cross-subsidization. For the case of the Central and Western regions, residential heat loads are eliminated entirely. Similar to the opportunity analysis with cross-subsidization, the results in all three regions are highly sensitive to the level of market penetration achieved by district heating. At 100 per cent market penetration it is estimated that district heating could competitively supply about 25 per cent of the space and domestic hot water heating requirements of the cities and towns considered in the analysis. If district heating is only able to achieve 50 per cent market penetration this estimate reduces to about 5 per cent of space and domestic hot water requirements.

It would appear, however, from the results of the economic analysis that there is likely some opportunity for cross-subsidization in the Atlantic Region and to a lesser extent, in the Central and Western Region. Thus the results of the opportunity analysis, without cross-subsidization, are essentially an estimate of the minimum potential for district heating within the context of the assumptions used in the study.

TABLE 9-29

Regional Opportunity Analysis
(Without Cross-subsidization)

Region	Population$^{(1)}$	Annual Heat Consumption$^{(2)}$	Economically Attractive for District Heating 100% Penetration Energy	 Percent	 50% Penetration Energy	 Percent
	(000's)	10^6GJ	10^6GJ		10^6GJ	
Atlantic	546	24.72	7.62	31	1.18	5
Central	9103	410.54	104.91	26	22.49	6
Western	3442	163.67	37.10	23	7.49	5
Total	13091	598.93	149.63	49	31.16	5

Notes: (1) Population of cities listed in Table 1-4 for each region.

(2) Useful heat.

Any attempt to estimate the extent to which cross-subsidization could be used to increase the potential of district heating above these lower values would require site specific evaluations which are beyond the scope of this study. However the two approaches to analyzing the potential for district heating in Canada would appear to provide reasonable estimates of the upper and lower limits for its potential.

PART 10

ENVIRONMENTAL CONSIDERATIONS

PART 10 - ENVIRONMENTAL CONSIDERATIONS

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10.1 GENERAL

District heating is often perceived as a cause of improvement in the environmental quality for a community, because it is assumed that emissions can be less readily controlled at numerous small dispersed sources than at an equivalent central facility.

This is certainly true where the same or equally polluting fuels are used in both cases. But where district heating stations use coarse low-grade fuels (viz. coal, wood, peat, municipal solid waste) to replace heat provided by the combustion of high-grade fuels (viz. natural gas and light fuel oil), then a detailed comparison must be made for each such case to determine the impact of district heating on the environment. In making such comparisons, both direct and indirect effects upon the environment must be taken into account. Those effects upon the environment which take place at the plant and occur during the process of converting fuel or energy into heat or electricity are termed 'direct' effects, whereas those which are ancillary to the process and do not actually take place at the plant are termed 'indirect' effects.

A few examples of 'direct' and 'indirect' effects are listed below:

Item	Effect on the Environment	
	Direct	Indirect
- Gaseous emissions such as $SO_x/NO_x/CO_x/$ Hydrocarbons/Aldehydes/Particulates/ Dioxins	X	
- Solid residue, such as ash	X	

Item	Effect on the Environment Direct	 Indirect
- Thermal pollution discharged into lakes, streams & coastal waters by electrical power generating stations	X	
- Gaseous pollution caused by vehicular fuel transportation		X
- Pollution of surface and ground waters and of air by landfills.		X
- Flooding of inland areas by man-made reservoirs for generation of hydro-electric power, resulting in ecological imbalance, possible loss of species and sometimes loss of valuable land.		X
- Damage to environment and ecology by acid rain		X

This part of the report attempts a qualitative and, a limited, quantitative assessment of the impact of district heating on the environment in comparison with the impact of conventional heating systems used in Canada.

While each case needs to be studied on its own merits, to determine the sum resultant of direct and indirect environmental impacts of district heating, it is reasonably safe to say that heat pump technology should generally be reviewed on a priority basis for its prospective favourable impact on the environment, and incineration of municipal and industrial wastes should be reviewed in comparison with its landfill option. Similarly, since cogeneration utilizes fuel with twice the efficiency of electrical power production, its overall impact on the environment is likely to be favourable in many cases.

1011 PROTECTION OF THE ENVIRONMENT

Particulate and gaseous emissions in the flue gases produced by combustion processes are toxic to human, animal and plant life. Solid effluents, in the form of bottom ash and fly ash, constitute a further pollution hazard.

The relation between $SO2$ emissions and acid rain is the subject of extensive investigations, and it has been established that acid rain is the cause of considerable damage to delicate ecological balances in forests, lakes and streams. The loss already sustained in plant and aquatic life has not been fully estimated, and the long term effects are unknown.

Apart from SO_x, NO_x particulates and ash, some combustion processes also produce dioxins, which are potent poisons for all forms of life. Heavy metals and other trace elements in ash, unless contained in designed landfill will, by contaminating local soil and water regimes, have deleterious effects upon dependent life forms.

Other emissions, such as carbon monoxide, hydrocarbons and aldehydes are also environmentally noxious.

1012 DIFFERENCE BETWEEN CONVENTIONAL HEATING AND DISTRICT HEATING SYSTEMS

Space and domestic water heating systems are described as "conventional" when each building, or a physically connected group of buildings, is served by its own small heating furnace. On the other hand, when many buildings, and sometimes whole areas, are served by one or more comparatively large central heating stations, then this is termed a district heating system.

Central heating stations, which provide the heat to district heating networks may be designed either to generate heat only, or to generate "combined heat and electrical power" (CHP) by cogeneration technology.

Central heating stations and the fuels they use are fully described in Part 6 of this report.

1013 EMISSIONS AND EFFLUENTS FROM CONVENTIONAL AND DH SYSTEMS

For the reason that "conventional" and "district heating" systems consume different quantities and grades of fuel, when providing the same quantities of end-use heat, they differ in the emissions and effluents produced by their combustion processes.

10.2 ENVIRONMENTAL IMPACT OF CONVERSION TO DISTRICT HEATING

1021 EMISSIONS FROM CONVENTIONAL HEATING SYSTEMS

The Canadian fuels and energy used for home and building heating are mainly natural gas, oil and electricity. Heating of homes with wood is fairly common outside the major population centres but, since district heating is unlikely to extend into lightly populated or rural regions, this discussion will confine itself to natural gas, oil and electricity as the "conventional" fuels.

Part 6.4 of this study has estimated fuel consumptions for four sizes of district heating stations using a variety of fuels and operating in both heating only and cogeneration (CHP) modes.

1022 COMPARISON OF EMISSIONS AND ASH EFFLUENTS UPON CONVERSION TO DH SYSTEMS

Tables 10-1 to 10-5 compute figures of emissions for comparison between:

- "Base Case Conventional Heating Systems", and
- "Option Case DH Systems".

The following notes will serve to explain the data in Tables 10-1 to 10-11:

A. Emissions from conventional heating systems have been taken from an article by Gladys Sessler (Tenektron Inc.: "Environmental Effects of District Heating"), the information being reproduced here as Tables 10-7 to 10-9.

The figures in Table 10-8 indicate that when oil burning appliances are replaced by a coal fired district heating plant, SO_2 emissions are expected to be 70% to 100% of the original values. However, this estimate depends on some very important assumptions, namely:

.1 that 75 percent of the oil burned in buildings is distillate fuel oil burned in residential buildings;

.2 25 percent is residual fuel oil burned in commercial and institutional buildings;

.3 the average sulphur content is 0.22 percent for the distillate oil and 1.7 percent for the residual;

.4 the heating value of the coal is 23.26 MJ/kg and most importantly,

.5 the emission factor for SO_2 emissions from the district heating plant is the NSPS limit of 516 ng/J (1.2 lb/106 BTU).

B. Table 10-10 gives the nominal fuel characteristics for which emissions are estimated.

C. In Tables 10-2 to 10-5 emissions from district heating central plants are based on the National Guidelines for New Stationary Sources, and are related to the fuel consumption for heat production in both "heating only" and in "cogeneration (CHP) plants". For this reason, care has been taken to separate the fuel consumed for heat production from that used for electrical power production in CHP plants.

COMPARISON OF ANNUAL FUEL CONSUMPTIONS OF DH OPTION CASES WITH CONVENTIONAL BUILDING HEATING

CONVENTIONAL HEATING (BASE CASE)	CONVERSION TO DISTRICT HEATING (OPTION CASES)									
	ANNUAL FUEL CONSUMPTION OF DH SYSTEM REPLACING CONVENTIONAL SYSTEM (BY HEAT ONLY STATIONS)					ANNUAL FUEL CONSUMPTION OF DH SYSTEM REPLACING CONVENTIONAL SYSTEM (BY COGENERATION STATION)				
	DH CASE #	FUEL TYPES	SEASONAL EFFICIENCY THROUGH TO END-USE %	FUEL CONSUMPTION		DH CASE #	FUEL TYPES		FUEL CONSUMPTION	
				GJ x 10^3	% OF BASE CASE		COGENG UNIT	PEAKING UNIT	COGEN GJ x 10^3	PEAKING GJ x 10^3
- Base Case # A-0 - No. of Inhabitants 4,500 - Annual End-Use Heat Consumption (@ 45 GJ/Inh.) 203.0 x 10^3 GJ - Conventional Heating Fuels Gas/Oil - Seasonal Efficiency 60% - Annual Fuel Consumption 337.7 x 10^3 GJ - Required DH Plant Size for Conversion 18 MW_t - Max. Fuel Consumption Rate 103 GJ/h (1)	(A-1)	Gas	75.04	270	80	(A-7)	Gas	Gas	604.304	53.2
	(A-2)	Oil	77.93	260	77	(A-8)	Oil	Oil	574.088	50.8
	(A-3)	Coal	72.11	281	83	(A-9)	Coal	Gas	656.1	53.2
	(A-4)	Wood	61.77	328	97	(A-10)	Coal	Oil	656.1	50.8
	(A-5)	Peat	61.77	328	97	(A-11)	Wood	Gas	706.568	53.2
	(A-6)	MSW	61.77	328	97	(A-12)	Wood	Oil	706.568	50.8
						(A-13)	Peat	Gas	706.568	53.2
						(A-14)	Peat	Oil	706.568	50.8
						(A-15)	MSW	Gas	706.568	53.2
						(A-[illegible])	MSW	Oil	706.568	50.8
- Base Case # B-0 - No. of Inhabitants 37,510 - Annual End-Use Heat Consumption (@ 45 GJ/Inh.) 1,688.2 x 10^3 GJ - Conventional Heating Fuels Gas/Oil - Seasonal Efficiency 60% - Annual Fuel Consumption 2813.7 x 10^3 GJ - Required DH Plant Size 150 MW_t - Max. Fuel Consumption Rate 855 GJ/h (1)	(B-1)	Gas	79.8	2116	75	(B-7)	Gas	Gas	4831.2	410.8
	(B-2)	Oil	83.6	2020	72	(B-8)	Oil	Oil	4606.5	394.4
	(B-3)	Coal	79.8	2116	75	(B-9)	Coal	Gas	4890.8	410.8
	(B-4)	Wood	75.1	2250	80	(B-10)	Coal	Oil	4890.8	394.4
	(B-5)	Peat	71.25	2370	84	(B-11)	Wood	Gas	5825.6	410.8
	(B-6)	MSW	66.49	2540	90	(B-12)	Wood	Oil	5825.6	394.4
						(B-13)	Peat	Gas	5825.6	410.8
						(B-14)	Peat	Oil	5825.6	394.4
						(B-15)	MSW	Gas	5825.6	410.8
- Base Case # C-0 - No. of Inhabitants 75,030 - Annual End-Use Heat Consumption (@ 45 GJ/Inh.) 3376.4 x 10^3 GJ - Conventional Heating Fuels Gas/Oil - Seasonal Efficiency 60% - Annual Fuel Consumption 5627.3 x 10^3 GJ - Required DH Plant Size for Conversion 300 MW_t - Max. Fuel Consumption Rate 1710 GJ/h (1)	(C-1)	Gas	79.81	4230	75	(C-6)	Gas	Gas	10764.48	796
	(C-2)	Oil	83.60	4038	72	(C-7)	Oil	Oil	10275.2	765
	(C-3)	Coal	79.81	4230	75	(C-8)	Coal	Gas	10764.48	796
	(C-4)	Wood	75.05	4498	80	(C-9)	Coal	Oil	10764.48	765
	(C-5)	Peat	71.25	4738	84	(C-10)	Coal	Coal	10764.48	796
						(C-11)	Wood	Gas	11445.8	766
						(C-12)	Wood	Oil	11445.8	795
						(C-13)	Wood	Coal	11445.8	766
						(C-14)	Peat	Gas	11445.8	796
						(C-15)	Peat	Oil	11445.8	765
- Base Case # D-0 - No. of Inhabitants 375,250 - Annual End-Use Heat Consumption (@ 45 GJ/Inh.) 16886.0 x 10^3 GJ - Conventional Heating Fuels Gas/Oil - Seasonal Efficiency 60% - Annual Fuel Consumption 28143.8 x 10^3 GJ - Required DH Plant Size for Conversion 1500 MW_t - Max. Fuel Consumption Rate 8552 GJ/h (1)	(D-1)	Gas	79.8	21160	75	(D-4)	Gas	Gas	58414.0	3982.4
	(D-2)	Oil	83.60	20198	72	(D-5)	Oil	Oil	55758.4	3832.0
	(D-3)	Coal	79.80	21160	75	(D-6)	Coal	Gas	58414.0	3982.4
						(D-7)	Coal	Oil	58414.0	3832.0
						(D-8)	Coal	Coal	58414.0	3982.4

NOTES: (1) This is based on a Load Duration Curve with a Utilization Time of 3291 h/a, as used for the DH Option Cases.

Table 10-1

COMPARISON OF THE MAJOR GASEOUS EMISSIONS AND ASH EFFLUENTS BETWEEN BASE CASE A-0 AND OPTION (DH) CASES A-1 TO A-16 LISTED IN TABLE 10-1

CASE #	MAXIMUM HOURLY FUEL CONSUMPTION (1) GJ/h			FLUE GAS EMISSIONS (2)						TOTAL ASH kg/h	
				SO							
BASE CASE A-0 GAS OIL	 103 103			 0.0175 26.5		 3.97 3.79		 TRACE 4.41		 - -	
DH OPTION CASES A-1 to A-16	COGEN (CHP) UNIT		HEATING UNIT								
	POWER	HEATING		POWER	HEATING	POWER	HEATING	POWER	HEATING	POWER	HEATING
A-1			82		0.014		7.5		<3.53	-	-
A-2			79		20.38		10.19		< 3.4		5.53
A-3			85.3		22.00		22.00		3.7		307-546
A-4			99.7		13.6-25.7		2-5		4.3		60
A-5			99.7		25.7		8-16		4.3		180-907
A-6			99.7		13.6-25.7		8-16		4.3		817-2353
A-7	44	25	43.8	0.0075	0.0115	3.78	5.92	<1.89	<2.96		-
A-8	41.4	24	41.5	10.71	16.89	5.36	8.44	<1.78	<2.82	2.91	4.59
A-9	49	26	43.8	12.7	6.7	12.73	10.47	<1.91	<3.19	176-314	94-166
A-10	49	26	41.5	12.8	17.3	12.75	12.05	<1.91	<3.09	176-314	97-169
A-11	51	30	43.8	6.9-13.16	4.1-7.74	1.03-2.63	4.37-5.27	<2.21	<3.19	31	18
A-12	51	30	41.5	6.91-13.17	14.79-18.43	1.41-2.65	5.59-6.85	<2.21	<3.09	31.09	20.91
A-13	51	30	43.8	13.16	7.74	4.13-8.23	6.17-8.57	<1.91	<3.09	92-464	54-273
A-14	51	30	41.5	13.17	18.43	4.15-8.25	7.75-10.15	<2.21	<3.09	92-464	57-276
A-15	51	30	43.8	6.9-13.16	4.1-7.74	4.13-8.23	6.17-8.57	<2.21	<3.19	418-1204	246-708
A-16	51	30	41.5	6.91-13.17	14.79-18.43	4.15-8.25	7.75-10.15	<2.21	<3.09	418-1204	249-711

NOTES: (1) Emission value is based on the maximum hourly fuel consumption for each case, and the maximum hourly fuel consumption is computed as follows:

- For Base Cases: Taken from Table 10-1
- For DH Option Cases: The DH Option Cases are numbered as in Table 10-1. These DH cases were developed for, and are tabulated in, Part 6 of this report. For each case the maximum hourly fuel consumption is computed at maximum station boiler rating. In the Cogeneration (CHP) DH Option Cases the fuel used for heating is shown seperately from that used for production of electrical power, so as to permit comparison with Base Cases on an equal footing.

(2) Flue gas emissions for Base Cases are based on data developed by G. Sessler (Tenckton Inc.: "Environmental Effects of District Heating"). Emissions for DH Option Cases are based on the "National Guidelines for New Stationery Services".

(3) Total maximum hourly fuel consumption for each case is the sum of the three GJ/h numbers in columns 2, 3 and 4.

Table 10-2

COMPARISON OF THE MAJOR GASEOUS EMISSIONS AND ASH EFFLUENTS BETWEEN BASE CASE B-0 AND OPTION (DH) CASES B-1 TO B-16 LISTED IN TABLE 10-1

CASE #	MAXIMUM HOURLY FUEL CONSUMPTION (1) GJ/h			FLUE GAS EMISSIONS (2)						TOTAL ASH kg/h	
				SO_2 kg/h		NO_x kg/h		PARTICULATES kg/h			
BASE CASE B-0											
GAS	855			0.144		33.1		TRACE		-	
OIL	855			220.6		31.6		<37		-	
DH OPTION CASES B-1 to B-16	COGEN (CHP) UNIT		HEATING UNIT								
	POWER	HEATING		POWER	HEATING	POWER	HEATING	POWER	HEATING	POWER	HEATING
B-1			642.8		0.11		55.3		<27.6		
B-2			613.6		158.3		79.2		<26.4		43
B-3			642.8		165.8		165.8		26.4		2314-4114
B-4			683.5		93-176.3		13.7-34.2		29.4		410
B-5			720.0		186		57.6-115.2		31		1296-6552
B-6			771.4		104.9-199		61.7-124		33.2		6325-18205
B-7	356.4	195	338.8	0.06	0.09	30.68	45.42	15.4	22.7		
B-8	339.9	186	318	87.7	130	43.75	65.05	14.62	21.68	23.69	35.31
B-9	363.3	195	333.8	93.64	50.36	93.68	79.02	16.07	22.33	1308-2325	702-1248
B-10	364.3	194	318	93.7	132.3	93.65	91.35	16.02	21.68	1308-2325	724-1270
B-11	458.1	207	333.8	62.44-181.54	28.06-53.06	9.13-22.93	32.87-39.07	19.77	23.23	275	124
B-12	458.1	207	318	62.5-118.6	110-135	9.1-22.9	45.2-51.4	19.72	22.58	275	146
B-13	447.1	218	333.8	115.54	56.06	35.78-71.48	46.12-63.62	19.27	23.73	805-4068	392-1984
B-14	447.1	218	318	115.6	138	35.75-71.45	58.45-75.95	19.22	23.08	805-4068	414-2006
B-15	431.1	234	333.8	58.44-111.54	32.06-60.06	34.48-68.78	47.42-66.32	18.67	24.33	3535-10174	1919-5522
B-16	431.1	234	318	58.5-116.6	114-142	34.45-68.75	59.75-78.65	18.62	23.68	3557-10196	1919-5522

NOTES: (1) Emission value is based on the maximum hourly fuel consumption for each case, and the maximum hourly fuel consumption is computed as follows:

- For Base Cases: Taken from Table 10-1
- For DH Option Cases: The DH Option Cases are numbered as in Table 10-1. These DH cases were developed for, and are tabulated in, Part 6 of this report. For each case the maximum hourly fuel consumption is computed at maximum station boiler rating. In the Cogeneration (CHP) DH Option Cases the fuel used for heating is shown separately from that used for production of electrical power, so as to permit comparison with Base Cases on an equal footing.

(2) Flue gas emissions for Base Cases are based on data developed by G. Sessler (Tenecktion Inc.: "Environmental Effects of District Heating"). Emissions for DH Option Cases are based on the "National Guidelines for New Stationary Services".

(3) Total maximum hourly fuel consumption for each case is the sum of the three GJ/h numbers in columns 2, 3 and 4.

Table 10-3

COMPARISON OF THE MAJOR GASEOUS EMISSIONS AND ASH EFFLUENTS BETWEEN BASE CASE C-0 AND OPTION (DH) CASES C-1 TO C-16 LISTED IN TABLE 10-1

CASE #	MAXIMUM HOURLY FUEL CONSUMPTION GJ/h			FLUE GAS EMISSIONS						TOTAL ASH kg/h	
				SO_2 kg/h		NO_x kg/h		PARTICULATES kg/h			
BASE CASE C-0 GAS OIL	1710 1710			0.29 441		66.2 63.1		TRACE 73.5		- -	
DH OPTION CASES C-1 to C-16	COGEN (CHP) UNIT		HEATING UNIT								
	POWER	HEATING		POWER	HEATING	POWER	HEATING	POWER	HEATING	POWER	HEATING
C-1			1285.7		0.22		110.6		55.3		
C-2			1227		316.6		158.3		52.8		86
C-3			1285.7		331.7		331.7		55.3		4629-8228
C-4			1367		185.4-352.7		27.3-68.4		58.8		820
C-5			1440		371.5		115.2-230.4		61.9		2592-13104
C-6	837	392	643	0.143	0.177	72	89	35.84	44.56		
C-7	799	374	614	206.1	254.9	103.05	127.45	34.31	42.49	56	69.2
C-8	837	392	643	215.99	101.11	216	156.3	35.8	44.6	3013-5357	1411-2509
C-9	837	392	614	216	259.4	216	180.2	35.9	43.3	3013-5357	1454-2552
C-10	837	392	643	215.9	267	215.9	267	35.8	44.6	3013-5357	3726-6624
C-11	886	421	643	120.9-228.3	57-109	17.7-44.4	63.7-76.3	38	45.8	531.2	253
C-12	894	413	614	121.8-230.2	214.4-265.4	17.86-44.4	87.44-100.2	38.4	44.2	536.2	291
C-13	886	421	643	120.7-228.1	223-275	17.6-44.3	174.4-187	38	45.8	531.2-531.2	2568-4368
C-14	868	439	643	224.3	113	69.48-138.86	90.42-125.54	37.2	46.6	1563-7899	790-3995
C-15	868	439	614	224.2	271.4	69.48-138.86	114.32-149.44	37.3	45.3	1606-7942	790-3995
C-16	868	439	643	224.1	279	79.38-138.76	191.12-236.24	37.2	46.6	1563-7899	3105-8110

NOTES: (1) Emission value is based on the maximum hourly fuel consumption for each case, and the maximum hourly fuel consumption is computed as follows:

- For Base Cases: Taken from Table 10-1
- For DH Option Cases: The DH Option Cases are numbered as in Table 10-1. These DH cases were developed for, and are tabulated in, Part 6 of this report. For each case the maximum hourly fuel consumption is computed at maximum station boiler rating. In the Cogeneration (CHP) DH Option Cases the fuel used for heating is shown seperately from that used for production of electrical power, so as to permit comparison with Base Cases on an equal footing.

(2) Flue gas emissions for Base Cases are based on data developed by G. Sessler (Tencktion Inc.: "Environmental Effects of District Heating"). Emissions for DH Option Cases are based on the "National Guidelines for New Stationery Services".

(3) Total maximum hourly fuel consumption for each case is the sum of the three GJ/h numbers in columns 2, 3 and 4.

Table 10-4

COMPARISON OF THE MAJOR GASEOUS EMISSIONS AND ASH EFFLUENTS BETWEEN BASE CASE D-0 AND OPTION (DH) CASES D-1 TO D-8 LISTED IN TABLE 10-1

CASE #	MAXIMUM HOURLY FUEL CONSUMPTION GJ/h			FLUE GAS EMISSIONS						TOTAL ASH kg/h	
				SO_2 kg/h		NO_x kg/h		PARTICULATES kg/h			
BASE CASE D-0											
GAS	8552			1.44		331		TRACE		-	
OIL	8552			2206		316		368		-	
DH OPTION CASES D-1 to D-8	COGEN (CHP) UNIT POWER	COGEN (CHP) UNIT HEATING	HEATING UNIT	POWER	HEATING	POWER	HEATING	POWER	HEATING	POWER	HEATING
D-1			6428		1.1		552.8		< 276.4		
D-2			6136		1583		791.5		< 263.8		430
D-3			6428		1658.4		1658.4		276.4		23141-41139
D-4	4706	1960	3215	0.815	0.885	404.8	445	< 206.5	< 218.4		
D-5	4497	1869	3069	1160.2	1274	580.1	637	< 193.3	< 212.4	314	346
D-6	4706	1960	3215	1213.75	506.55	1214.3	782	< 202.5	< 222.3	16942-30118	7056-12544
D-7	4709	1957	3069	1214.6	1297	1214.7	901	< 202.4	< 216.2	16953-30137	7260-12740
D-8	4706	1960	3215	1213.3	1336	1213.3	1336	< 202.6	< 222.3	16942-30118	18630-33120

NOTES: (1) Emission value is based on the maximum hourly fuel consumption for each case, and the maximum hourly fuel consumption is computed as follows:

- For Base Cases: Taken from Table 10-1
- For DH Option Cases: The DH Option Cases are numbered as in Table 10-1. These DH cases were developed for, and are tabulated in, Part 6 of this report. For each case the maximum hourly fuel consumption is computed at maximum station boiler rating. In the Cogeneration (CHP) DH Option Cases the fuel used for heating is shown seperately from that used for production of electrical power, so as to permit comparison with Base Cases on an equal footing.

(2) Flue gas emissions for Base Cases are based on data developed by G. Sessler (Tenckton Inc.: "Environmental Effects of District Heating"). Emissions for DH Option Cases are based on the "National Guidelines for New Stationery Services".

(3) Total maximum hourly fuel consumption for each case is the sum of the three GJ/h numbers in columns 2, 3 and 4.

Table 10-5

SUMMARY MATRIX COMPARISON OF DATA DEVELOPED IN TABLES 10-1 THROUGH 10-5

FUEL FOR CONVENTIONAL HEATING SYSTEMS	SUMMARY OF ENVIRONMENTAL IMPACT (1) WHEN CONVERTING FROM CONVENTIONAL TO DH USING VARIOUS FUELS (2)																		
	FUELS FOR HEATING ONLY STATIONS						FUELS FOR COGENERATION (CHP) STATIONS: COGEN UNIT FUEL/(PEAKING UNIT FUEL)												
	GAS	OIL	COAL	WOOD	PEAT	MSW	GAS/ (GAS)	OIL/ (OIL)	COAL/ (GAS)	COAL/ (OIL)	COAL/ (COAL)	WOOD/ (GAS)	WOOD/ (OIL)	WOOD/ (COAL)	PEAT/ (GAS)	PEAT/ (OIL)	PEAT/ (COAL)	MSW/ GAS	MSW/ OIL
GAS:																			
SO_2	-	+	+	+	+	+	-	+	+	+	+	+	+	+	+	+	+	+	+
NO_x	+	+	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Part.	-	+	+	+	+	+	-	+	+	+	+	+	+	+	+	+	+	+	+
Ash	-	+	+	+	+	+	-	+	+	+	+	+	+	+	+	+	+	+	+
OIL:																			
SO_2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NO_x	+	+	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Part.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ash	-	+	+	+	+	+	-	-	+	+	+	+	+	+	+	+	+	+	+
GAS-ELECTRIC:																			
SO_2	-	+	+	+	+	+	-	+	+	+	+	+	+	+	+	+	+	+	+
NO_x	-	-	+	-	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-
Part.	-	-	+	+	+	+	-	-	+	+	+	+	+	+	+	+	+	+	+
Ash	-	+	+	+	+	+	-	-	+	+	+	+	+	+	+	+	+	+	+
OIL-ELECTRIC:																			
SO_2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NO_x	-	-	+	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Part.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ash	-	-	+	+	+	+	-	-	+	+	+	+	+	+	+	+	+	+	+
COAL-ELECTRIC:																			
SO_2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NO_x	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Part.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ash	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NUCLEAR-ELECTRIC:																			
SO_2	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
NO_x	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Part.	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Ash	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+

NOTE (1): (+) = More emission than Base Case
(-) = Less emission than Base Case
(o) = Emission about equal to Base Case

(2): Comparisons are based on emissions resulting from fuel used for 'heating' only in both conventional and DH Cases. Where cogeneration (CHP) is involved, those emissions related to the production of electrical 'power', as identified in Tables 10-2 to 10-5, have been omitted in making the comparison between Conventional Heating and DH Cases.

Table 10-6

Air Emission Factors: Combustion of Oil, Natural Gas, and Coal

	Buildings[a]				Power Plant			
	Fuel-Oil Combustion		Natural Gas Combustion		Fuel-Oil Combustion		Coal Combustion	
Pollutant	lb/10^3gal[b]	lb/10^6Btu[c]	lb/10^6ft^3[b]	lb/10^6Btu[d]	lb/10^3gal[b]	lb/10^6Btu[c]	lb/ton coal	lb/10^6Btu
Particulates	10-23[e]	0.093	19	.019	–[f]	0.1[f]	–[f]	0.1(.03)[f]
SO_2	142 S[g]	0.6	0.6[h]	.0006	–[f]	0.8[f]	–[f]	1.2(0.5)[f]
CO	5	.036	20	.02	3	0.02	1	.05
Hydrocarbons	3	.021	8	.008	2	0.01	.15	.0075
NO_x	12	.086	80-120[i]	.090	–[f]	0.30[f]	–[f]	.07(0.6)[f]
Aldehydes	2	.014	-	-	1	0.007	.005	.0025

---

[a] We assume that 75% of the heat load is from residential buildings burning distillate, and 25% from non-residential buildings burning residual fuel oil.

[b] Emission factors are from: "Compilation of Air Pollutant Emission Factor," EPA AP-42, April, 1973.

[c] Btu values for fuel-oil are: 5.85×10^6Btu/bbl, distillate; 6.3×10^6Btu/bbl, residual fuel-oil. For buildings, value used is $(0.75 \times 5.8 + 0.25 \times 6.3) \times 10^6 = 6.0 \times 10^6$Btu/bbl. For power plants, value used is that for residual fuel-oil.

[d] Assuming 1000 Btu/ft^3.

[e] The lower value represents distillate fuel oil, the upper value residual fuel oil. Value used is $0.75 \times 10 + 0.25 \times 23 = 13$ lb/10^3gal.

[f] Current new source performance standards (NSPS) are assumed for SO_2, NO_x, and particulates. Values in parentheses are upper limits that may be required by proposed revisions of NSPS.

[g] S equals percent by weight of sulfur in the oil. Value used is $0.75 \times .22 + 0.25 \times 1.7 = 0.6$%. (Average sulfur contents are from Reference (Hittmann I).

[h] Based upon sulfur content of 2000 grams/SCF.

[i] 80 lb/10^6ft^3 applies to "domestic", 130 lb/10^6ft^3 to commercial. Value used is $0.75 \times 80 + 0.25 \times 120 = 90$ lb/10^6ft^3.

Table 10-7

TABLE 10-8

Comparison of Local Air-Pollutant Emissions from Conventional and DH Heating Systems: Particulates, SO_2, NO_x from Heat Sources

	Pounds of Pollutant Emissions[a] (for every million BTU of fuel burned by the conventional system)				
	Fuel Use Scenario (Conventional-DH)				
	Oil-Oil	Gas-Oil	Oil-Coal	Gas-Coal	Electric-Electric (Coal) (Coal)
Energy Savings (ES)	49%-64%	46%-64%	49%-64%	46%-64%	75%-83%
Pollutant Emissions					
Particulates					
- Conventional	.093	.019	.093	.019	.1
- DH	.051-.036	.054-.036	.051-.036	.054-.036	.025-.017
- DH Conv x 100[b]	55%-40%	≥200%	55%-40%	≥200%	25%-20%
SO_2					
- Conventional	0.6	.0006	0.6	.0006	1.2
- DH	.41-.29	.43-.29	.61-.43	.65-.43	.30-.20
- DH Conv x 100[b]	70%-50%	≥1000%	100%-70%	≥1000%	25%-20%
NO_x					
- Conventional	.086	.090	.086	.090	1.2
- DH	.15-.11	.16-.11	.36-.25	.38-.25	.18-.12
- DH Conv x 100[b]	≥120%	≥120%	≥300%	≥300%	25%-20%

[a] For every million BTU of fuel burned by the conventional system, pollutant emissions in pounds are as follows:

$$E_c \text{ (lb)} = EF_c \times 1$$

$$E_{DH} \text{ (lb)} = EF_{DH} \times (1 - ES)$$

where E_c = lb of emissions from the conventional system;

E_{DH} = lb of emissions from the DH system.

EF_c and EF_{DH} are emission factors for the conventional and DH systems in $lb/10^6$ BTU, as listed in Table 10-7. (Emission factors applied to DH are those for power plants, which for particulates, SO_2, and NO_x, are current NSPS.)

ES = fractional energy savings when DH replaces the conventional system, (See Table 1).

[b] DH/Conv x 100 = the emissions in the DH system as a percentage of emissions in the Conventional system. Values are rounded to the nearest 5%.

TABLE 10-9

Comparison of Local Air-Pollutant Emissions from Conventional and DH Heating Systems: CO, Hydrocarbons and Aldehydes from Heat Sources

	Pounds of Pollutant Emissions[a] (for every million BTU of fuel burned by the conventional system)				
	Fuel Use Scenario (Conventional-DH)				
	Oil-Oil	Gas-Oil	Oil-Coal	Gas-Coal	Electric-Electric (Coal) (Coal)
Energy Savings (ES)	49%-64%	46%-64%	49%-64%	46%-64%	75%-83%
Pollutant Emissions					
CO					
- Conventional	.036	.02	.036	.02	.05
- DH	.010-.0072	.011-.0072	.026-.08	.027-.018	.0125-.0085
- DH Conv x 100[b]	30%-20%	55%-35%	70%-50%	135%-90%	25%-20%
Hydrocarbons					
- Conventional	.021	.008	.021	.008	.0075
- DH	.0051-.0036	.0054-.0036	.0038-.0027	.0041-.0027	.0019-.0013
- DH Conv x 100[b]	25%-20%	10%-5%	20%-15%	50%-35%	25%-20%
Aldehydes					
- Conventional	.014	----	.014	----	.00025
- DH	.0035-.0025	.0035-.0025	.00013-.00009	.00013-.0009	.00006-.00004
- DH Conv x 100[b]	25%-20%	----	<1%	----	25%-20%

[a] See Comment [a], Table 10-8.

[b] See Comment [b], Table 10-8.

TABLE 10-10

Nominal Fuel Characteristics for Waste Management Material and Heat Balances

	Peat	Wood	Coal* (Bituminous)	Oil
Moisture Content (wt%)	50	40	6	0.2
Calorific Value Wet basis (MJ/kg)	11	10	30	43
Ultimate Analyses (wet basis)				
Carbon (wt%)	27.5	30	72.4	85.3
Oxygen (wt%)	17.5	25.2	4.7	0.40
Hydrogen (wt%)	2.5	3.6	4.7	11.2
Sulphur (wt%)	0.1	0.06	2.8-5.6	0.5-6.3
Nitrogen (wt%)	0.5-1.4	0.1-0.3	0.75-1.1	0.20-0.3
Ash (wt%)	1-5	0.6-1.2	9.4	0.1
Excess Air for Combustion (wt%)	25	25	20	5

* Nova Scotia Bituminous Coal

TABLE 10-11

Power Plant Nitrogen Oxide Emissions

	NO_x Emissions as NO for			
	Peat	Wood	Coal	Oil
	mg/MJ	mg/MJ	mg/MJ	mg/MJ
Measured (Hasanen, 1982)	80-160	-	280-360	100-105
Calculated (for fuels in Table 8-5)	1000-2900	200-600	500-800	100-150

mg/MJ - mg NO per MJ heat content of fuel

D. Table 10-11 provides data on NO_x emissions from power plants using fuels specified in Table 10-10.

10.3 COMPARISON OF ENVIRONMENTAL IMPACTS

Table 10-6 summarizes all results qualitatively in matrix form and shows the direction of environmental impact:

(+) = Worse, i.e. higher emission on conversion from the conventional base case to the district heating option case.

(-) = Better, i.e. lesser emissions on conversion from the conventional base case to the district heating option case.

(0) = No significant change on conversion.

10.4 ENVIRONMENTAL IMPACT OF REPLACING GAS FIRED HEATING APPLIANCES WITH DISTRICT HEATING

Where individual gas fired heating appliances are replaced by a district heating plant burning coal or low grade fuels, the emission of particulates, SO_2 and NO_x would increase. It should be noted that the increase stated here is an increase in the total amount of pollutants emitted and not a local ground level concentration.

Conceivably, a district heating plant with its much taller stack (and therefore much larger dispersion of the exiting pollutants) could exhibit local ground level concentrations not significantly different from the individual gas fired appliances; but in view of the hazard of acid rain, it is necessary to emphasize the distinction between abatement and dispersion.

Controlling emissions is not so much a problem of technology as of economics. Particulate emissions are already being controlled at power plants by use of equipment such as electrostatic precipitators, baghouses (fabric filters), cyclones (mechanical dust collectors) and flue gas scrubbers. Likewise emissions of SO_x can be controlled using such means as coal washing, furnace limestone injection and flue gas desulphurization. Methods being tried for NO_x control include "off-stoichiometric" fuel firing and fludized bed combustion. While the above means may not reduce total emission levels to the comparable level from individual gas fired installation, a reasonable compromise between cost of emissions removal and level of emissions should be attainable.

One emission that will be reduced by replacing gas fired individual installation with a district heating plant is that of hydrocarbons. A coal fired district heating scheme, for instance, is expected to exhibit hydrocarbon releases that would be 35% to 50% of those from the individual installations replaced as illustrated in Table 10-9.

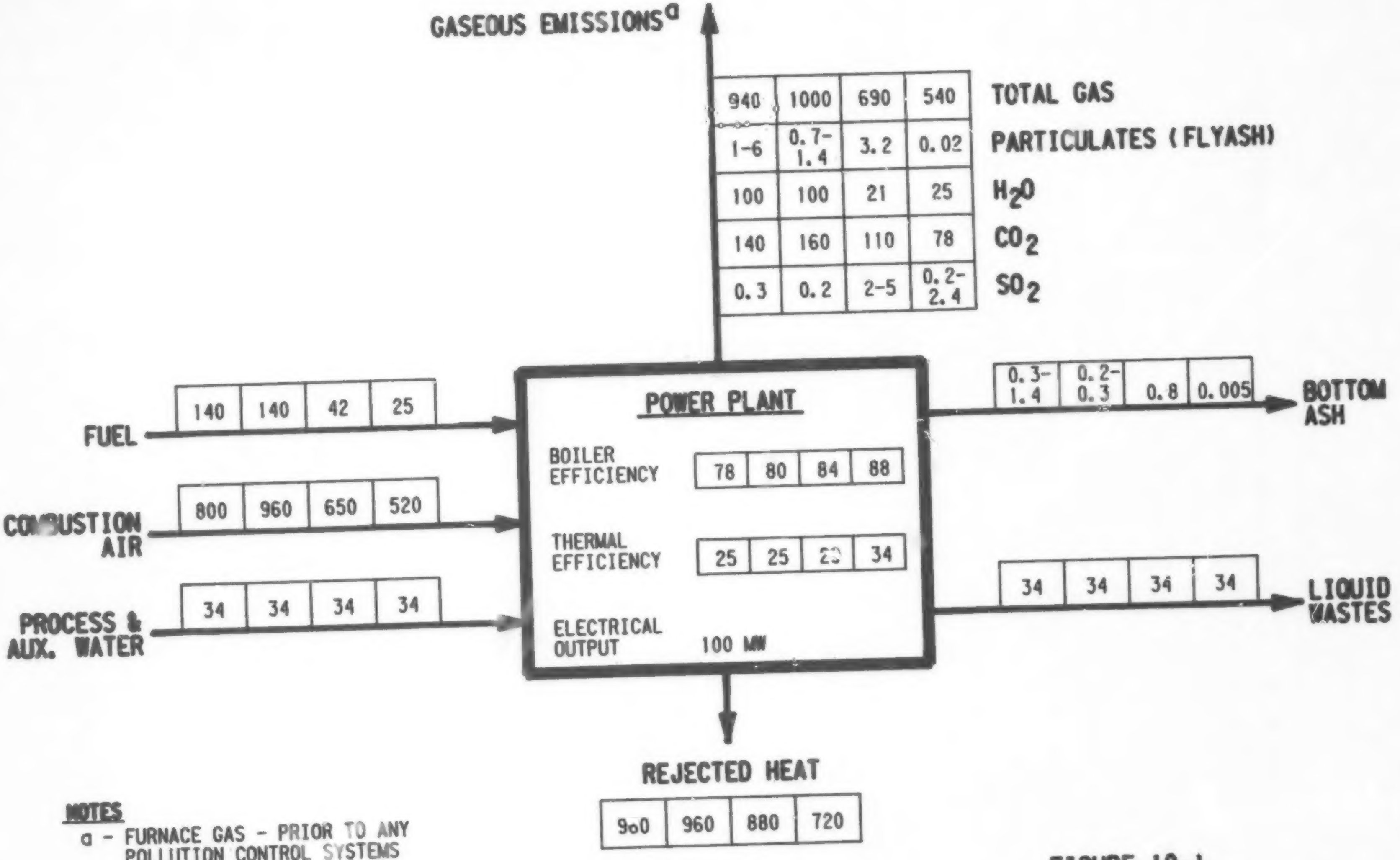
10.5 ENVIRONMENTAL IMPACT OF REPLACING OIL FIRED HEATING APPLIANCES WITH DISTRICT HEATING

When oil burning appliances are replaced by a district heating plant that is to burn a fuel other than oil, the environmental impact will depend to a large extent on the pollution legislation in conformance with which the plant is designed to operate. In the case of particulate emissions, for instance, Tables 10-3 and 10-8 indicate that emissions from a coal fired plant would be less than those produced by the individual oil fired heating appliances, even though oil has a much lower concentration of particulate matter. This prediction, however, is based on the application of the American Environmental Protection Agency's "New Source Performance Standards" (NSPS) for coal fired power stations of 43 ng/J (0.1 lb/106 BTU) of heat input being applied to the coal fired district heating plant, and the fact that individual heating appliances are not required to have any means of particulate control.

In Canada, the current allowable limit for particulate emissions from power stations as given in the National Guidelines for New Stationary Sources is also 43 ng/J (0.1 lb/10^6 BTU) of heat input. This limit is, however, for all fuels. Thus, regardless of the fuel to be fired in a district heating plant in Canada, given that it must operate under the above guideline, it would therefore emit less particulates to the atmosphere than the oil fired heating appliances it replaced.

A material and heat balance for a power plant of 100 MWe output for peat, wood, coal and oil firing is shown in Figure 10-1. The balances are based on the nominal fuel analyses given in Table 10-10. It can readily be seen that peat, wood and coal can all be expected to produce significantly more particulate matter than oil. Therefore, for the peat, wood and coal fired plants to meet the same level of particulate emissions to the atmosphere as an oil fired plant, greater amounts of particulates must be removed from the gas stream prior to its discharge to atmosphere. This collected particulate (flyash) must of course also be disposed of, the chief method presently being landfills. Controlling atmospheric particulate emissions from wood, coal or peat fired plants may thus mean large landfills and therefore more problems (i.e. leaching) associated with such sites. Increased alternative uses for flyash such as filler in pavement or building blocks could be one solution to the landfill problem.

[100,77]DSS101 .DGN


GASEOUS EMISSIONS^a
940 | 1000 | 690 | 540 TOTAL GAS
1-6 | 0.7-1.4 | 3.2 | 0.02 PARTICULATES (FLYASH)
100 | 100 | 21 | 25 H_2O
140 | 160 | 110 | 78 CO_2
0.3 | 0.2 | 2-5 | 0.2-2.4 SO_2
FUEL
140 | 140 | 42 | 25
COMBUSTION AIR
800 | 960 | 650 | 520
PROCESS & AUX. WATER
34 | 34 | 34 | 34
POWER PLANT
BOILER EFFICIENCY
78 | 80 | 84 | 88
THERMAL EFFICIENCY
25 | 25 | 23 | 34
ELECTRICAL OUTPUT
100 MW
0.3-1.4 | 0.2-0.3 | 0.8 | 0.005
BOTTOM ASH
34 | 34 | 34 | 34
LIQUID WASTES
REJECTED HEAT
900 | 960 | 880 | 720

NOTES

a - FURNACE GAS - PRIOR TO ANY POLLUTION CONTROL SYSTEMS

PEAT	WOOD	COAL	OIL

UNITS

HEAT - GJ/h
MATERIALS - t/h
EFFICIENCY - %

FIGURE 10-1
WASTE MANAGEMENT
MATERIALS AND HEAT BALANCES
CAPACITY 100MWe

Similarly, the impact on SO_x emissions to the atmosphere will depend on the emission legislation applied to district heating plants.

The emissions factors for SO_x in Canada, given in the National Guidelines for New Stationary Sources, are not fuel dependent in as much as the limits are based not on type of fuel burned but on levels of uncontrolled SO_x production. Moreover, there is no upper limit for total SOx emission to the atmosphere as units emitting more than 2580 ng/J (6.0 lb/106 BTU) uncontrolled are to be controlled so that a minimum of 90% of the uncontrolled emission is captured before release to the atmosphere. Given, however, that the district heating plant do not exceed an uncontrolled SOx production of 2580 ng/J (6.0 lb/106 BTU), then the district heating plant in Canada would be limited to a total SOx emission of 258 ng/J (0.6 lb/106 BTU). In this case, it would therefore appear that in Canada an even bigger reduction in SOx emissions is possible by replacing oil burning heating appliances with a coal fired district heating plant than is indicated in Table 10-8.

SO_2 production from a peat or wood fired power plant is significantly less than from a coal fired plant and may even be less than from an oil fired plant. Meeting SO_x emission limits from a peat or wood fired district heating plant can therefore be expected to pose no major technical problems.

Coal fired district heating plants can be expected to produce more NO_x than the replaced oil burning heating appliances. Table 10-8 shows a predicted 300% increase based on the NSPS allowable limit of 301 ng/J (0.7 lb/106 BTU) being applied to the district heating plant. Interestingly, this increase in NOx emission would occur even for an oil fired heating plant. This, because a much higher flame is achieved in the district heating plant's combustion source than in individual oil burning appliances. The higher flame temerature contributes to the formation of nitrogen oxides.

A peat or wood fired district heating plant, on the other hand, may not increase emissions of NO_x, and may even reduce them. Table 10-11 shows that, while the calculated values for nitrogen oxide production from peat and wood are greater than that for oil, the measured value for peat may, in fact, be less than for oil. It should be noted that the flame temperatures for peat and wood are lower than those of oil or coal. This is due largely to the much higher moisture content of the former and therefore much lower heating values (HHV) of peat and wood in the as-fired state. This lower flame temperature would normally be expected to help reduce the formation of nitrogen oxides. More data is requried to confirm the figures computed for formation of nitrogen oxides during the combustion of peat or wood to determine the impact on NO_x emissions by the replacement of oil fired units by a district heating system fired by these low grade fuels.

Table 10-9 indicates that emissions of CO, hydrocarbons and aldehydes are all significantly lower when oil burning appliances are replaced by a coal fired district heating plant.

An activity for which there are no quantitative results of the benefits to be achieved by its elimination is the transportation of oil by tank trucks (usually diesel) to individual buildings. The emissions of air pollutants associated with the truck transport (NO_x, SO_x, CO, particulates) of oil is thought to be significant. Traffic congestion, particularly in busy metropolitan areas, could only be helped by elimination of these vehicles. However, such savings could be offset or even reversed by the transportation of low grade (low energy and bulk density) fuels to district heating central stations.

10.6 ENVIRONMENTAL IMPACT OF REPLACING ELECTRIC HEATING APPLIANCES

Special cases exist (and it is for these that the argument for district heating is the clearest) when all electric heating appliances are replaced by district heating, and the district heating plant and the electric power generating plant burn the same fuel.

In such cases, the percentage of district heating to non-district heating pollutants is simply the calculated average energy used by district heating as a percentage of the energy used by the replaced system. Table 10-6 indicates that, when all electric resistance heating is replaced by district heating, the pollutants produced by the district heating plant can be expected to be less than those emitted by the electricity generating plant.

Equally impressive is the fact that, since less coal would have to be mined, cleaned, transported and stored at the district heating plant, the environmental disruptions associated with coal fuel cycle activities would be reduced. These disruptions include such activities as solids and acids in liquid effluents, solid wastes, disrupted land and particulate emissions.

In the case of electricity generated by hydro-electric means, it is clear that all forms of district heating would have greater environmental impacts by comparison.

10.7 ENVIRONMENTAL IMPACT ON THERMAL POLLUTION

Thermal pollution from a district heating (cogeneration) plant would come from the same two sources as those in a conventional power plant, i.e. the sensible heat in the flue gas discharged up the stack and the waste heat rejected from the cycle to the cooling system.

A district heating plant operating in a cogeneration mode can always be expected to produce less thermal pollution for the cooling system to handle than a conventional power plant. There would be no thermal pollution and no need for a cooling system in the particular case where the district heating plant uses a backpressure turbine.

As less total energy is consumed with the adoption of a district heating scheme and, therefore, less waste heat byproduct produced, the thermal pollution discharged by the stack of a district heating plant can also reasonably be expected to be less than that discharged from the conventional power plant and the individual appliances to be replaced.

10.8 CONCLUSION

The above discussion on the environmental impacts of district heating schemes has tried to illustrate that:

.1 actual quantitative results will require site specific and fuel specific information, and that

.2 the environmental impact of replacing oil and gas fired appliances with a coal or low grade fuel fired district heating plant will not, in all instances, be beneficial.

We have also attempted to indicate the directions of changes (positive/worse or negative/better) in environmental quality to be expected for a district heating plant burning various fuels and in what areas (SO_x, NO_x, particulates etc.) these changes would occur.

There is no argument that, from an energy point of view, district heating (regardless of the fuel considered) saves energy and therefore fuel. When this desire to conserve fuel by the inherent energy savings to be had from district heating is combined with the desire to further increase the savings in a particular fuel (i.e. gas or oil) by removing it as a fuel choice for the district heating plant, however, environmental complications are introduced. The ultimate decision for or against a district heating plant, in this case (which is expected to be the norm), will then depend on the value placed on the fuel (energy) saved versus the cost placed on the environmental impacts or the means to abate them.

PART ELEVEN

BARRIERS AND INCENTIVES FOR DISTRICT HEATING

PART ELEVEN - BARRIERS AND INCENTIVES FOR DISTRICT HEATING

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11.1 GENERAL

District heating is a viable and accepted form of heat production and distribution in many countries in Europe and has been the subject of renewed interest and development in the United States in recent years. The particular factors and objectives that led to the interest in and development of district heating in these countries have been discussed in Part 4 of the report. There has also been considerable interest in Canada,particularly at government levels, in the development of district heating as a means of promoting energy efficiency and self-sufficiency, conserving high grade fossil fuels, and encouraging capital investment and urban development.

Notwithstanding this interest, existing steam DH systems in Canada, rather than expanding, are confronted with eroding customer bases, rising costs, increased competition and a very uncertain future. A number of specific DH development opportunities have been identified and economic feasibility, based on European DH technology, has been demonstrated; however the promoters of these projects have, almost without exception, been unsuccessful in converting these opportunities into operating DH systems. It has become increasingly clear that, while demonstrated economic feasibility continues to be a fundamental prerequisite to the development of district heating, it is not the sole determinant of success or failure. A number of non-economic factors that can frustrate implementation, as well as possible methods of overcoming them, have been identified in various Canadian and U.S. DH studies and are discussed in the context of the current Canadian environment in the following pages. In addition some of the less measurable benefits or incentives to implementation are identified. While it is recognized that many of these issues are complex and interrelated and thus difficult to classify or "compartmentalize" the following headings have been used to organize and focus the discussion.

Subscriber Attitudes
Developer Attitudes
Regulatory Aspects
Financial Considerations
Competing Energy Forms
Technological Factors
Environmental Factors
Government Policies

11.2 SUBSCRIBER ATTITUDES

Modern hot water DH systems have the potential under certain circumstances to offer the residential, commercial and industrial subscriber a number of significant advantages over owning and operating individual heating systems. These advantages include competitive heating costs, lower maintenance costs, improved air quality, smaller space requirements, and greater safety when compared to conventional fossil fuel-fired systems. Unfortunately, the Canadian public has very little knowledge of district heating. To the extent that Canadians do have an awareness of district heating, it is, in all probability, based on experience with existing steam systems which are unlikely to have fostered a positive or progressive image of the technology. While hot water DH systems are well established and accepted in Europe they represent a "new" technology that is not understood in Canada. Consequently district heating faces the normal resistance to change that confronts any new technology. However, due to the characteristics of the technology and the very fact that it is an energy technology, district heating is likely to encounter greater than normal consumer resistance.

District heating is a capital intensive technology that requires substantial front-end investment not only on the part of the developer but also on the part of the subscriber to replace or retrofit existing heating systems. For example, in the case of the City of St. Paul, Minnesota, while a total of $45.8 million was spent to design, construct and finance the heat production and distribution systems, a further $22 million was required to convert and upgrade subscriber systems (in many cases based on steam) to accept hot water as the primary heat source [111]. This capital cost, representing almost 50 per cent of the cost of the DH production and distribution system constituted a serious deterrent to potential subscribers, particularly non profit cultural organizations, social service agencies, and hospitals. While such large institutional facilities were essential base loads for the economic viability of the district heating system, these subscribers were least able to cope with the capital requirements of connecting to the system. This problem was overcome in St. Paul through a variety of conversion loans, grants and private and corporate donations.

In the case of new construction the individual purchaser may not consider the type of heating system as one of the more important criteria in the purchase decision. Consequently builders and contractors seeking to minimize capital costs could be deterred by the capital cost of district heating. For multi-family dwellings the owner/developer is also likely to favour lower first cost to the detriment of district heating.

In addition to the front-end capital investment, the subscriber retrofitting to a DH system will be faced with the inconvenience and disruption associated with the actual installation of the distribution system and the retrofitting of the existing individual heating system. This disruption can also contribute to consumer resistance particularly for commercial customers who may be temporarily prevented from conducting their business.

While the potential subscriber is virtually assured that he will experience the front-end costs and inconvenience of connecting to a DH system, the benefits are perceived to be somewhat less certain since they are typically based on extended payback periods and projections of the future cost of alternative energy sources. Unfortunately Canadians have been exposed over the past decade to a number of conflicting forecasts of what the future holds for the energy sector. Projections of future shortages and rising prices for conventional energy sources such as oil, gas and electricity have been quickly followed by projections of energy surpluses and stable or even declining (in real terms) energy prices. The demonstrated inability by all levels of government to predict the future availability and cost even of indigenous energy resources has made Canadians understandably skeptical and reluctant to participate in energy solutions that require substantial up-front capital commitments in order to obtain long-term future benefits in energy costs. After a decade of rapidly rising energy prices and concerns about availability, Canadians have, since the recession of 1982, witnessed the growth of energy surpluses, particularly electricity and natural gas. This situation has led to intense competition among the oil, natural gas, and electrical energy sectors for a greater share of the Canadian space heating market.

Cost of [illegible]

In the face of present energy surpluses and an emerging expectation that these surpluses will continue in the future, the economic incentives to become more energy efficient and the penalties for lack of progress in this area are diminishing. Canadians are more inclined to take a "stand pat, wait and see" attitude towards the introduction of new capital intensive energy technologies.

In addition, increasing awareness of the benefits of conserving conventional energy resources has, over the past decade, led to increased use of higher levels of insulation in both existing and new buildings and use of waste heat storage, computerized energy control systems and other innovative design methods particularly in new commercial construction and as a result, the absolute energy requirements of many buildings are tending to decline. It has been estimated that present state of the art buildings consume only one-fifth of the energy per unit area consumed by the average building constructed in the 1970's [C1]. The availability of higher efficiency heating systems makes the continued use of conventional energy sources more cost effective not only for new construction but also for retrofitting or replacement of existing systems.

A number of studies have also suggested that North Americans' sense of individualism may result in a negative attitude towards centralized or "community" heat systems such as district heating notwithstanding the fact that district heating is no more centralized than other well accepted energy distribution modes such as electricity or natural gas.

If district heating is to gain acceptance in Canada's increasingly competitive space heating market, potential subscribers must first be confident that the technology offers an assured supply of reliable and competitively priced thermal energy over the long term. Subscribers must also be encouraged to base their heat source decisions on life-cycle costs rather than low capital costs or even short-term payback periods. Detailed and understandable economic and financial analyses setting out the level of initial investment, the expected payback period and life-cycle costs of district heating and its competitors under a broad spectrum of projected long-term alternative heating costs must be made available to the potential subscriber to assist in the decision making process. The developer must create confidence that it has the technical and financial resources to develop a reliable source of fuel, and an operating system and organizational structure capable of producing and delivering thermal energy with a level of convenience and reliability of supply exceeding that of traditional individually owned and operated systems. In addition, one of the more significant barriers to subscriber acceptance - the burden of retrofitting existing buildings - must be minimized for potential subscribers who generally have limited access to capital by providing favourable financing and/or creating a pricing formula for district heating which tends to offset retrofit costs when compared to alternative heating costs.

Potential subscribers must also be made aware that hot water district heating technology is neither obsolete nor experimental but is rather a well established cost effective method of space heating that has proven itself in Europe in climatic regimes similar to those experienced in Canada.

To the extent that credible economic analysis supports the development of district heating and innovative financing and energy pricing can be developed to offset the disincentives to implementation created by connection and retrofit costs, the problem then becomes one of effectively disseminating this information, along with information on the other benefits of district heating, to potential subscribers in a readily understood format. This is a marketing problem which, due to the site specific nature of most district heating projects, is likely to require a marketing plan which is, for the most part, tailored to the economic and other benefits of that particular project rather than the use of mass marketing approaches that are suitable to conventional space heating technologies.

11.3 DEVELOPER ATTITUDES

District heating requires a very large initial capital investment, with the rate of return on that capital, and in fact the return of the capital itself, contingent on the ability of the DH project to compete with alternative energy sources for a period of 20 or 30 years into the future. As a result, a potential investor or developer of a DH project will be as concerned as potential subscribers with the volatility of energy prices that has been exhibited in the past and the high level of uncertainty associated with long-term forecasts of energy prices. Consequently, the conclusions of the economic analysis supporting the project must be robust under the full range of possible future costs of alternative energy sources in order to provide confidence in the long-run economic feasibility of the project

However, the relative cost of alternative energy sources is not the only factor likely to threaten the economic feasibility of district heating. The developer will require a significant initial and continuing subscriber heat-load over which to distribute the relatively large fixed costs associated with the capital investment in the system. This problem can to some extent be managed by developing the system first in high heat-load areas and by limiting capital costs during the development phase by the use of relatively low cost mobile package boilers. These boilers can be subsequently moved to new development areas or used as peaking units. Nevertheless, maintaining a continuing subscriber heat load remains a significant concern. In order to achieve maximum market penetration it might be desirable to implement a DH system which would minimize the subscribers' cost of retrofitting existing systems. However, due to the variety of existing heating systems, this may be difficult to accomplish. In addition, such design criteria may conflict with the objective of minimizing system life-cycle costs. In this regard developers would likely favour a mandatory hook-up policy or long-term heat supply contracts in order to transfer some of the financial risk of the DH project to the subscribers. It is unlikely however that a mandatory hook-up policy would be acceptable in Canada where individuals have historically been free to choose, within the limits of requirements for public safety and environmental considerations, whatever heat source was economically accessible to them. Long-term heat supply contracts are also not likely to be acceptable to potential residential, commercial, or industrial users since similar commitments are typically not required by competing conventional energy sources. This is an area where significant support for district heating projects could be provided by all levels of government through committments to connect government facilities on a long-term contractual basis to district heating systems.

As noted in Part Seven, the most economical method of implementing district heating is to install it initially in areas of highest heat load concentrations and subsequently expand into areas of lower heat load densities. A developer will require long-term franchise and expropriation rights in order to be assured that such long-range development plans can proceed without future interruption. These rights are normally granted to regulated public utilities in return for accepting the constraints and obligations of regulation - the more notable of which normally include the obligation to provide continuing service at reasonable cost to all economically accessible customers within the franchise area and the limitation to a "just and reasonable" rate of return on invested capital.

Fear of regulation is cited in a number of U.S. studies as one of the more significant deterrents to private investment in district heating. This is due to the perception that current regulatory practices in the U.S. and Canada (Canadian regulatory practice has developed in large measure based on the U.S. practice) do not fully accommodate the requirements of district heating. Since district heating is based on the distribution of heat through extensive in-ground piping networks it is clear that franchise rights and reasonable access to rights-of-way are fundamental to development. However the distribution of heat through a DH system is not a natural monopoly as is, for example, the distribution of electricity. Electricity is a product for which, for many end-uses, there is no practical substitute and therefore little competitive pressure. End-users of district heating, however do have a number of viable alternatives and consequently district heating would be subject to substantial competitive market forces. Consequently private developers are reluctant to expose themselves to a regulatory system which would force them to invest capital to provide service to marginally economic customers and at the same time would limit returns to capital to levels which, in the light of significant competitive and financial risks, would be considered unacceptably low. Even existing investor-owned or crown-owned utilities that are presently subject to some form of rate regulation are unlikely to consider diversification into an area such as district heating if there is a significant possibility that they might be subject to rate regulation which might deny them a rate of return on investment commensurate with the perceived higher business and financial risks associated with the development and marketing of a new capital intensive heat energy technology.

In view of these concerns with regulation and the minimal risk to the public of monopolistic pricing policies due to the existence of readily available substitutes, it may be reasonable to allow the development and marketing of district heating to occur within the constraints of normal business practise and contractual obligations rather than in a regulated environment.

Even with the risk of some of the negative aspects of regulation removed, district heating may remain unattractive to potential private sector investors when faced with high initial capital costs, limited access to, and high real costs of capital, long construction lead times, the risk of major construction cost overruns and the prospect of extended payback periods. Capital intensive utility-type activities with marginal rates of return are unlikely to attract private sector equity capital, for which the primary objective is to maximize return on investment, since it can command higher returns with lower risk in other areas.

In this regard existing energy utilities are probably among the best equipped organizations to deal with many of these concerns in the implementation of district heating. Such utilities typically operate capital intensive systems with long-lived assets and extended pay-back periods. Due to their continuing need for capital they have established their credit worthiness in the financial markets and thus have reasonable access to the longer term financing that is required to produce a reasonable return on capital intensive projects. Utilities also work with the longer planning horizons that are required in the development of district heating and have developed, in operating their current line of business many of the administrative, organizational and technical capabilities required to cope with the regulatory and operating requirements of a DH system. In certain circumstances electric utilities may also offer an economically attractive heat source through the operation of cogeneration plants.

It is unlikely however, that district heating would ever represent a large component of a major energy utility's total business activity. As a secondary or peripheral activity to a utility's principal line of business, district heating might not receive the level of attention and commitment at the corporate level necessary to ensure its continued viability. In addition, to the extent that district heating, natural gas and electricity may be in direct competition in many areas, significant involvement of an established energy utility in DH projects raises concerns of conflict of interest which may operate to impede the development of district heating.

Municipal governments as potential developers of district heating also possess many of the attributes necessary to overcome a number of the institutional barriers to district heating. Questions of franchise areas or access to right-of-way would not concern a municipal owner. Like utilities, most large municipalities are experienced in long range planning, normally have reasonable access to capital and have less demanding rate of return on investment objectives than the private sector although, as a minimum, debt issued for a DH project will normally be expected to be self-supporting.

Through the operation of normal services such as water distribution many municipalities have already acquired or developed many of the skills and resources necessary to operate a district heating system. As discussed in Part Four, municipal governments have played a major role in the development of district heating in many parts of Europe and are one of the driving forces behind the renewed interest in district heating in the United States. For many municipal governments in the U.S. district heating is viewed as a means to an end rather than an end in itself. District heating may be viewed as part of the solution to a municipal solid waste problem, a method of encouraging urban renewal or attracting industry by exploiting a local low cost energy source. As indicated in the discussion of U.S. activity in district heating, municipalities owning their own thermal-electric generating facilities may be particularly well positioned to develop district heating if a significant heat load exists and the electric plant can be economically retrofitted to operate in a cogeneration mode. The City of Jamestown New York is an example of a city with this favourable combination of resources.

Although a number of municipal electric utilities operate in Canada, particularly in Ontario, the number of municipally owned thermal-electric generating facilities is limited. A few examples however are Summerside in Prince Edward Island which operates a small diesel generating facility and the City of Edmonton with natural gas fired generating capacity. As discussed earlier, the City of Edmonton, with a climate and population concentration that creates a high heat load density, municipally owned electric generating facilities, and an anticipated low cost fuel source when the Genesee Plant is completed, may be one of the more promising Canadian sites for district heating and this option is being activity pursued by its municipal government.

Irrespective however of whether it is investor, utility, municipal or other governmental ownership of district heating that may be most conducive to development of district heating, the fundamental uncertainty confronting any potential investor in a district heating project remains its long-term economic feasibility in the present and prospective environment of uncertain and volatile energy prices.

11.4 REGULATORY ASPECTS

At the present time the federal government regulates interprovincial oil and natural gas pipelines and the export of oil, natural gas and electricity. Regulation of intraprovincial energy distribution (natural gas and electricity) is essentially a provincial responsibility. Natural gas and electricity are distributed by a mix of investor, crown and municipally owned utilities. Virtually all investor-owned and increasingly, crown-owned energy utilities are subject to some form of rate regulation or regulatory review. Municipal utilities however are for the most part not subject to rate regulation except in situations where the utilities' activities extend beyond their municipal boundaries.

The decision to regulate district heating and the scope of such regulation will in all probability rest with individual provinces and the decision will likely be affected by factors such as the ownership of the enterprise, the size of the system and the existence of economically competitive substitutes.

As discussed in Part 11.3, rate regulation and rate of return regulation of district heating would likely be perceived as a significant deterrent to private investment and to investor-owned or crown-owned utilities and as noted there likely exists sufficient competitive pressure in most areas to make this form of regulation unnecessary.

However, even if it is considered inappropriate to regulate district heating systems, to the extent that an existing utility were to assume an ownership role, regulators would have legitimate concerns such as ensuring that the utility's customers were not indirectly exposed to the business and financial risks of the district heating system; that assets of the regulated enterprise were not used in unregulated activities without appropriate compensation; and that administrative and operating costs were reasonably allocated to ensure that the utility's customers were not subsidizing district heating customers. If district heating were expected to displace a significant portion of a utility's load (and typically the displaced load would be high volume commercial and industrial load with a relatively low cost of service) regulators would be concerned about the impact on utility rates of distributing fixed costs over a smaller sales base. On the other hand, in situations where electric utilities are faced with large and costly generation expansion programs, regulators may be inclined to take a more positive attitude towards the development of district heating based on cogeneration, owned either by the utility or an independent developer, as a means of spreading capital costs over a large sales base and holding electricity cost down.

11.5 FINANCIAL CONSIDERATIONS

The large initial capital requirements and risks associated with district heating may constitute a significant barrier to the financing of a proposed district heating project. The perceived "newness" of the technology particularly if based on a non-conventional fuel source, its capital intensive nature, long pay-back period and the substantial competitive pressures to which the project would be exposed all serve to increase the perceived riskiness of district heating in the minds of potential investors and lenders who, as a result of highly volatile financial markets over the past five years, have increasingly shifted funds away from high risk ventures to high quality low risk investments while at the same time demanding historically high real rates of return. In this type of environment financing for a district heating project may be either prohibitively expensive or simply unavailable unless steps are taken to lower the perceived risks of the project to a level acceptable to the financial community.

Ownership of the project by entities such as utilities or municipalities having relevant related experience, established credit worthiness, reasonable access to capital and possibly government guarantees would serve to reduce risk.

Construction contracts based on firm lump sum bids would serve to transfer some of the construction risk from the developer/lender to the contractor. Firm long-term "all events" heat supply contracts with large creditworthy customers would shift much of the financial and business risks of a district heating project from the owner to its customers. Both of these approaches were recommended by the financial advisors to the District Heating Development Company of St. Paul Minnesota to obtain the highest possible rating on a bond issue that represented two-thirds of the financing for the St. Paul district heating project. The developers were able to obtain firm contracts for project construction, however they faced considerable resistance from potential customers to a proposed 30 year heat delivery contract with limited rights of termination [111]. While the developers were ultimately successful in marketing a modified 30 year agreement in which customers accepted, among other things, a contingent obligation to pay a proportionate share of debt service costs in the event aggregate customer demand fell below a specified level [70], the situation illustrates the type of difficulties likely to be faced by developers when confronted with the often conflicting requirements of marketability of the product on one hand and financability of the project on the other.

As discussed in Part 11.3 this is an area where acceptance of long-term "all events", "cost of service" type heat delivery contracts for large government owned facilities could significantly enhance the financability of a DH project. Financial viability in project financing is often a function of the enforceability of "all events" contracts with the project's customers and the credit worthiness of these customers.

11.6 COMPETING ENERGY FORMS

While there are a number of different fuel types with which district heating must complete in the space heating market such as oil, natural gas, electricity, coal, and wood, over 90 per cent of Canada's residential and commercial energy requirements are met by oil, natural gas or electricity. These established energy forms are offered to Canadian consumers at their average cost of production (based on the historical embedded cost of plant and equipment) which is typically below their long-run marginal costs. District heating, as a new heat source must install and develop its system at current costs which places district heating, or any new energy technology, at a significant economic disadvantage.

In addition developments in the energy sector over the past few years have resulted in increased competitive pressure for district heating. As discussed in Part Five oil as a heating fuel has been losing market share to electricity and natural gas over the past decade largely due to the high relative price of oil, concerns about continued availability and the impact of various government policies and programs such as the Canadian Oil Substitution Program.

During the same period, total Canadian domestic and export sales of natural gas have remained relatively static at about 2800 petajoules per year while additions to reserves have averaged almost 5000 petajoules per year. While much of the resulting surplus has received export approval, increasing indigenous U.S. supplies, declining demand and high Canadian prices have resulted in actual exports falling below authorized levels. Since 1982, natural gas exports have averaged only 40 per cent of authorized levels. In domestic markets growth in demand has been slow due to a relatively weak economy and increasing energy efficiency. Given this situation the National Energy Board is currently projecting an excess supply of natural gas until the turn of the century and possibly beyond [01].

Looking at the supply/demand situation in the electrical sector, electricity demand grew at very high and stable rates through the sixties and early seventies. Electric utilities faced with extended lead times to bring on additional generating capacity, committed for new generating capacity in anticipation of a continuation of future load growth at historical rates. In the event, electricity demand growth has slowed considerably in recent years with the result that existing generating capacity is substantially in excess of current requirements and this excess is expected to persist into the 1990's.

As a result of the abundant supplies of both natural gas and electricity there has been intense competition between these two fuels, particularly in Central Canada, over the displacement of oil's remaining market share.

Gas distribution systems have expanded in Quebec into regions east of Montreal and the Government of Saskatchewan has indicated that Saskatchewan Power Corporation will expand gas distribution systems to rural markets. Commercial development of the Scotian Shelf reserves in the early 1990's should make gas available in Nova Scotia and New Brunswick and the Government of British Columbia is considering construction of a natural gas pipeline to Vancouver Island. In addition to increased access to the Canadian market some gas distribution , recognizing the substantial deterrent that conversion costs may represent to individual consumers are offering financial assistance, over and above federal government grants under the Canadian Oil Substitution Program and the Industrial Conversion Assistance Program, to residential, commercial and industrial consumers to convert off oil. The federal and some provincial governments are providing encouragement, in addition to conversion grants to convert to natural gas. The federal and Alberta governments have agreed to introduce volume discounts for a three year period to industrial gas consumers and the Quebec government has eliminated provincial sales tax on sales of natural gas.

The electrical sector is also responding to present competitive pressures. Hydro Quebec is aggressively marketing hybrid (electric-oil) heating systems to residential and commercial customers and is offering supplemental conversion grants. Financial assistance for conversion of oil-fired industrial boilers and discounts of up to 50 per cent for use of electricity in new plants and plant expansions are also being offered. Surplus electricity is being priced at 90 per cent of the price of heavy oils and coal. Ontario Hydro has also initiated marketing programs aimed at promoting greater use of electricity in the residential, commercial and industrial sectors.

As noted in Part 6, the development and increasing availability of high-efficiency oil and natural gas furnaces and electric heat pumps will, in the future tend to reduce and even eliminate the advantage in thermal efficiency that heat-only district heating systems have enjoyed over individual conventional furnaces.

The energy environment just described is a very different one, and one much less hospitable to potential district heating projects than the environment anticipated only four or five years ago in which substantial increases in conventional energy costs were expected and there was a perceived need to preserve high-grade fuels such as gas and oil for industrial feed stock and transportation purposes.

In addition to expected direct competitive pressure from natural gas and electricity arising from the current and projected surpluses of these energy forms, the surplus of electrical generating capacity may also have a negative impact on the practicality of one of the more economic forms of heat production for district heating - cogeneration.

As discussed in Part 6, cogeneration - the simultaneous production of electricity and heat - can provide significant cost savings due to the high conversion efficiency achieved by the process. However since a cogeneration plant produces joint products it is necessary to allocate the costs of the plant, both capital and operating, to each of the products on some rational and equitable basis, particularly if the price for one or both of the products is set by regulation rather than by market forces. A full discussion of the various methods of allocating cogeneration costs between heat and electricity is beyond the scope of this study since the topic is extremely complex. A number of approaches have been developed which have relied to varying degrees on both the laws of thermodynamics and the theories of economics. One of the studies undertaken in conjunction with the Minneapolis St. Paul district heating development identified and evaluated eight different methods for allocating cogeneration costs, some favouring heat and some favouring the electricity product [188].

The issue has been resolved to some extent in the United States by the passage of Section 210 of the 1978 Public Utility Regulatory Policies Act (PURPA) which sets the ground rules for the purchase by electric utilities of electricity from cogenerators. This provision of the National Energy Plan was originally conceived as an incentive for the development of cogeneration which was considered to be hampered by a perceived unwillingness of utilities to allow cogenerators to attach to the grid, low purchase rates for cogenerated energy, high utility rates for back-up capacity and supplemental energy, and concern among industries that cogeneration facilities might be subject to public utility regulation. Among PURPA's provisions it required utilities to hook-up cogenerators, exempted cogenerators from public utility regulation, and perhaps most important from the point of view of this discussion established a ceiling purchase rate for cogenerated electricity as the incremental cost to the electric utility of alternative electric energy. When the Federal Energy Regulatory Commission (FERC) issued regulations for PURPA it defined "incremental cost" as "avoided cost". Avoided cost includes "avoided energy costs" - typically the cost of fuel and some operation and maintenance cost - and can also include "avoided capacity costs" if the purchase of electricity from a cogenerator permits an electric utility to avoid the need to construct a generating unit, to build a smaller, less expensive plant or to reduce firm power purchases from another utility. Avoided capacity cost credits are generally only available in utility systems with low reserve capacity.

FERC regulations did not however stipulate contractual terms between utilities and cogenerators. Consequently U.S. utilities have in many cases been able to negotiate a lower purchase price than their avoided costs by offering cogenerators the long-term purchase contracts that are often required in order to ensure the financial viability of the cogeneration project.

The concept of paying avoided cost for cogenerated electricity is supported by a number of Canadian electric utilities as a reasonable basis of compensation since it ensures that electric utility customers will not be required to pay more for cogenerated electricity than they would for electricity from conventional sources. A recently released study [156] has indicated that most of the Canadian electric utilities surveyed are prepared to purchase cogenerated electrical energy at a price that is generally related to avoided fuel cost but a much smaller proportion of the survey group are prepared to recognize cogenerated electrical capacity.

In view of the surplus of Canadian electricity, prices for cogenerated energy are likely to be subject to competitive pressure and utilities are likely to be unenthusiastic about the prospect of purchasing significant quantities of cogenerated electricity at prices very different from avoided energy cost.

11.7 TECHNOLOGICAL FACTORS

Technological factors generally favour centralized heat generation for community use rather than dispersed individual home and building heating systems.

The technical incentives to movement in the direction of community district heating systems in Canada are:

- Lower overall fuel consumption for the same end-use heat requirement.
- Improvement in national efficiency of fuel use by the application of cogeneration (CHP) systems wherever economically warranted. The economics of CHP are good in many situations, particularly in cases where local consumer(s) of electrical power can accept all of the generated power of the CHP station.
- By virtue of dispersed location, CHP can result in significant savings in utility transmission and distribution losses when it feeds power to consumer(s) in its immediate vicinity.
- Even when the power generated by a CHP station exceeds the demand of consumer(s) in its immediate vicinity, such power can be fed to the local utility grid, thereby saving not only fuel at the utility plant, but also utility system losses associated with transmission and distribution of power.
- District heating systems, by using low grade fuel and energy resources, can save high grade fuels such as natural gas and

oil for priority use in transportation, chemicals and fertilizer industries.

- District heating systems are energetically more efficient because they can use low grade energy (otherwise wasted) which is closer to the end-use temperature than the energy use in conventional gas and oil fired heating appliances.

- District heating systems can also be used to provide district cooling.

- District heating central heating plants operate at higher seasonal load factors than do individual home and building heating appliances.

- District heating has potentially higher reliability due to standby equipment and systems compared with individual home units, which do not have standby.

- District heating transmission and distribution networks and control systems have been in commercial operation successfully for a couple of decades, and the technology is well advanced and established.

- User equipment to accept and apply energy from district heating networks is also commercially available and has years of commercial operating experience.

- A major technical advantage of district heating can be availed of by institutions such as hospitals and universities who already have their own central heating facilities. By integrating the institutional heating facilities into the district heating scheme they become part of a large system with improved performance characteristics, reliability, control and economics.

A small and inexpensive heat meter is currently under development in the Netherlands. To date, the heat meters available have been expensive, and this has been considered something of a drawback, because billings to district heating consumers have been computed and not by their own individual consumptions, but by a proportional share of a group consumption. This is in the nature of a technical barrier and should be overcome as soon as possible. However, it must also be stated that the actual billing systems have not created any real problem as long as district heating has been more economical than individual home heating.

11.8 ENVIRONMENTAL FACTORS

No generalizations are possible with regard to the environmental barriers to and incentives for district heating. Part 10 of this report deals in detail with the impacts of replacing conventional heating systems with district heating systems under a variety of scenarios. It is clear from the analysis in Part 10 that each case must be individually evaluated. Very few simple and direct conclusions are permissible. The few that are, may be listed briefly as follows:

- Electrical space and water heating sourced by hydro-electric power is the cleanest form of energy utilization.

- Natural gas fired district heating generates less pollution than conventional gas fired heating or a combination of gas and oil fired conventional heating.

- Oil fired district heating generates less pollution than oil fired conventional heating.

- Since other district heating fuels do not directly replace conventional fuels, no simple and direct comparisons are possible.

- Under cogeneration (CHP) scenarios, care should be taken to compute separately the proportions of total fuel consumption which are applied to production of heat and electrical power so as to compare the environmental effects of heating only in both the conventional and district heating cases. The environmental effect of the electrical power generation in CHP mode can then be separately compared with that of the utility-electrical power which the cogenerated power replaces.

11.9 GOVERNMENT POLICY

This study has indicated that district heating appears to be an economically competitive method of providing space heating in larger urban centers across the country notwithstanding general expectations of constant real prices or even negative real price changes in competing conventional energy forms for the intermediate and long-term future. The study results also indicate, however, that the economic feasibility of district heating is dependant on it achieving a very high level of market penetration. A reduction in market penetration from 100 per cent to 50 per cent is estimated to reduce the economic potential for district heating by about 80 per cent due to lost economies of scale. However, it is unlikely that district heating could achieve the high levels of market penetration required to maximize the economic benefits of the technology without the significant support of all levels of government.

While the federal and provincial governments play significant roles in the energy sector, municipal governments, which appear to have taken leadership roles in district heating initiatives in Europe and the United States, are with the exception of municipal electric utilities in Ontario, not significantly involved in energy management in Canada. There are very few municipalities involved in the production and distribution of primary or secondary energy forms that might be compatible with development of district heating.

In addition, responsibilities in the energy sector are divided between the federal and provincial governments. This makes the type of detailed national and regional planning and rationalization of competing energy forms (which might favour district heating in some instances) that has taken place in some European countries difficult to accomplish in Canada.

Federal government initiatives in the energy sector in recent years have been oriented towards promoting energy conservation and shifting off oil in order to achieve energy self-sufficiency rather than promoting any specific alternative energy form. Grants provided under the Canadian Oil Substitution Program have been effective in reducing oil consumption but the major beneficaries of the policy of oil substitution have been the other conventional energy sources, natural gas and electricity which have absorbed most of oil's lost market share.

The Forest Industry Renewable Energy Program, however, is an example of a program oriented toward the use of wood waste (and now incineration) as an energy source. There is some direct financial support available through programs like the Atlantic Energy Conservation Investment Program and indirect assistance in the form of accelerated capital cost allowances for energy conservation and oil substitution technologies. For the most part, however, direct support for alternative technologies has been in the form of feasibility study support and support for demonstration projects through the Conservation and Renewable Energy Demonstration Program (more recently ENERDEMO). However, with the recent development of surpluses of natural gas and electricity, it is not clear to what extent the conservation of these high grade energy forms remains a priority with government.

To the extent, however, that the conservation of high grade fuels and energy forms continues to be a long-term objective of government, then the ability of district heating to make a significant contribution towards this goal may be the incentive required for federal and provincial governments to adopt a positive stance towards the technology. As discussed earlier district heating does offer significant potential for energy conservation due to improved conversion efficiency relative to conventional individual heating systems. To the extent that low grade fuels such as coal, wood, peat or municipal solid waste burned in a district heating plant can be substituted for oil, gas or electricity consumed in individual heat plants even greater conservation of high grade fuels can be achieved.

Potential benefits to municipalities which would induce them to promote the development of district heating range from:

(i) providing a solution to the problem of disposing of municipal solid waste;

(ii) providing a focus for urban development and renewal;

(iii) increasing local employment opportunities through the development of a heat load for local low grade energy resources.

(iv) increasing economic activity within the region by retaining consumer expenditures for spacing heating requirements within the local economy.

(v) increasing the attractiveness of the municipality as a place to live and work due to the availability of low cost heat.

European experience, and more recently, U.S. experience indicates that municipal governments have played a pivotal role in the development of district heating. As noted earlier, the role of Canadian municipal governments in the energy sector has, with some notable exceptions, been relatively modest. If district heating is to develop in Canada, federal and/or provincial governments must create an awareness at the municipal level of district heating and the significant direct and indirect benefits that the technology can offer to municipalities. The objective of such an information program would be to encourage municipalities to assume, as they have in other countries, a leadership role in the promotion and development of the technology. Without the active and enthusiastic support of municipal government it is unlikely that district heating could achieve the level of market penetration necessary to make it economic.

Municipalities should also be encouraged to engage in the development of long-term energy plans for their communities on a basis similar to the type of regional and municipal energy planning that is carried out in many European communities. Such plans would not carry the force of law as they do in some countries in Europe however, they could be used to ensure that individual low grade fuel energy projects within the community were implemented in such a manner that they could ultimately be connected and integrated into a single multiple source heat system.

There is also a need to increase the awareness of district heating among the general public. As noted earlier, marketing programs designed to outline the benefits of district heating in quantitative terms will likely have to be tailored to specific projects. Central governments however, could play a valuable role in increasing general awareness and credibility in alternative energy technologies (such as district heating) and their potential benefits through the development and distribution of informational material to the general public.

In addition, to efforts to increase general awareness of district heating, there are a number of ways in which government can provide direct support for district heating.

Governments at all levels are owners of, and tenants in significant amounts of commercial office space. A policy of connecting government owned facilities, and favouring the leasing of commercial office space from buildings connected to district heating systems could go a long way to providing district heating projects with the important initial major baseload customers necessary to make them economically and financially viable.

Financial assistance will also likely be necessary for both developers and end-users of district heating if high market penetration levels are to be achieved. This assistance can take a variety of forms and would likely include:

(i) financial support for district heating feasibility studies, particularly for cities and towns having the attributes likely to favour district heating;

(ii) favourable tax treatment of private investment in district heating distribution and end-use systems.

(iii) assistance in project financing, both through grants and provision of low interest loans.

All of the above types of assistance have been offered in the United States to promote the development of district heating and were employed for example in the cases of St. Paul and Trenton to assist in financing the study and construction of their respective hot water DH systems.

Finally, and perhaps most importantly from the point of view of maximizing market penetration, financial assistance will be required to assist the end-user in dealing with the cost of retrofitting existing building stock to district heating. This assistance, provided either directly by government, or indirectly through the developer could take the form of:

(i) favourable tax treatment of investment in end-user systems;

(ii) grants to offset the cost of retrofit; or

(iii) low interest loans, with repayment schedules related to the savings in energy costs. The objective of such loans could be, for example, that the total cost of district heating to the end-user, including loan amortization, would not exceed his cost of heating with his existing system.

APPENDIX I

LEVELIZED COSTS

APPENDIX I

LEVELIZED COSTS

For any given heating service there may be upfront capital expenditures, on-going fuel and maintenance costs, and perhaps periodic replacements of capital items (for example a furnace). Consequently the total actual expenditure per GJ of useful heat delivered can vary considerably from year to year. The levelized cost of useful heat is the constant value which if assigned to each unit of useful heat consumed over the study period results in present value equal to the present value of the uneven stream of costs incurred to produce it. A simple example will be used to illustrate the point.

Year	1	2	3	4	5	Total
Capital Costs	$1700	$ -	$ 50	$ -	$ -	
Maintenance Costs	50	50	50	50	50	
Fuel Costs	300	310	320	330	340	
Total	2050	360	420	380	390	
Discount Factor @ 5%	.9524	.9070	.8638	.8227	.7835	
Present Value of Total Cost	$1952.40	$ 326.50	$ 362.80	$ 312.60	$ 305.60	$3,289.90
Useful Heat (GJ)	100	100	100	100	100	
Discounted Value of Useful Heat (GJ)	95.24	90.70	86.38	82.27	78.35	432.94

$$\text{Levelized Cost per GJ} = \frac{\text{Total present value of costs}}{\text{Total present value of GJ's}} = \frac{\$3,259.90}{432.94} = \$7.5297$$

Levelized Cost per GJ	$7.5297	$7.5297	$7.5297	$7.5297	$7.5297	
Useful Heat (GJ)	100	100	100	100	100	
Total levelized cost	$ 752.97	$ 752.97	$ 752.97	$ 752.97	$ 752.97	
Discount Factor @5%	.9524	.9070	.8638	.8227	.7835	
Present Value of Levelized Cost	$ 717.10	$ 682.90	$ 650.40	$ 619.50	$ 590.00	$3,259.90

The example shows an uneven stream of costs incurred to provide a constant useful heat output of 100 GJ per annum over a five year priod. The cost of useful heat ranges from a high of $2050 in year 1 to a low of $360 in year 2. The present value of the uneven stream of costs incurred to provide 100 GJ of useful heat per annum over the five year period is $3,259.90.

The levelized cost per GJ, calculated as the total present value of the costs incurred to provide 100 GJ per annum over the five year period divided by the discounted value of the energy per annum is $7.5297 per GJ. The example demonstrates that a constant levelized cost $7.5297 per GJ applied to the annual heat consumption of 100 GJ results in a constant cost stream over the five year period which has a present value of $3.259.90, equal to the present value of the uneven cost stream.

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